Exhibit No.__(BGM-1CT)
Docket No. UE-140762 *et al.*
Witness: Bradley G. Mullins
REDACTED VERSION

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFICORP D/B/A PACIFIC POWER & LIGHT COMPANY, Respondent.	)	DOCKET NOS. UE-140762 and UE-140617 *(consolidated)*
In the Matter of the Petition of PACIFIC POWER & LIGHT COMPANY, For an Order Approving Deferral of Costs Related to Colstrip Outage	)	DOCKET NO. UE-131384 *(consolidated)*
In the Matter of the Petition of PACIFIC POWER & LIGHT COMPANY, For an Order Approving Deferral of Costs Related to Declining Hydro Generation	)	DOCKET NO. UE-140094 *(consolidated)*

CONFIDENTIAL RESPONSIVE TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF

BOISE WHITE PAPER, L.L.C.

CONFIDENTIAL PER PROTECTIVE ORDER IN WUTC DOCKET NO. UE-140762

REDACTED VERSION

October 10, 2014

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EXHIBIT LIST

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bradley G. Mullins, and my business address is 333 SW Taylor Street, Suite 400, Portland, Oregon 97204.

Q. PLEASE STATE YOUR OCCUPATION AND ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am an independent consultant representing industrial customers located throughout the western United States. I am appearing on behalf of Boise White Paper, L.L.C. ("Boise"), which is served by Pacific Power & Light ("PacifiCorp" or the "Company").

Q. PLEASE SUMMARIZE YOUR EDUCATION AND WORK EXPERIENCE.

A. I received Bachelor of Science degrees in Finance and in Accounting from the University of Utah. I also received a Master of Science degree in Accounting from the University of Utah. After receiving my Master of Science degree, I worked at Deloitte Tax, LLP, where I was a Tax Senior providing tax consulting services to multi-national corporations and investment fund clients. Subsequently, I worked at PacifiCorp Energy as an analyst involved in regulatory matters primarily involving power supply costs. I began performing independent consulting services in September 2013. I currently provide consulting services to utility customers, independent power producers, and qualifying facilities on matters ranging from power costs and revenue requirement to power purchase agreement negotiations. A further description of my educational background and work experience can be found in Exhibit No.___(BGM-2).

Q. WHAT TOPICS WILL YOUR TESTIMONY ADDRESS?

A. My testimony addresses matters related to the Company's revenue requirement, including net power costs ("NPC"), its proposed mechanism for tracking the power costs associated with renewable portfolio standards ("RPS") resources, and its proposals for deferred accounting relating to an extended outage at the Colstrip facility, declining hydro conditions, and the Merwin Fish Collector.

Q. ARE OTHER WITNESSES SUBMITTING TESTIMONY ON BEHALF OF BOISE IN THIS PROCEEDING?

A. Yes. Boise Exhibit No.___(MPG-1T) contains the Responsive Testimony of Mr. Michael P. Gorman, who will discuss issues related to cost of capital. The impact of Mr. Gorman's cost of capital recommendation is summarized in the revenue requirement figures presented in my testimony. In addition, Boise Exhibit No.___(RRS-1T) contains the Responsive Testimony of Mr. Robert R. Stephens, who will discuss issues related to cost of service and rate spread.

Q PLEASE PROVIDE AN OVERVIEW OF YOUR TESTIMONY.

A. I make the following recommendations and my testimony is organized respectively:

1. **Revenue Requirement Issues.**

   a. **Pro-forma Capital Additions.** The Washington Utilities and Transportation Commission ("WUTC" or the "Commission") should reject the Company's proposal to include pro-forma capital additions in revenue requirement, with the exception of the Merwin Fish Collector. Removing these expenditures will result in a $3.8 million reduction to revenue requirement.

   b. **End of Period Rate Base.** The Commission should reject the Company's proposal to include end of period ("EOP") rate base balances in revenue requirement. The Company's current practice of almost continuous rate cases mitigates the impact of regulatory lag and the need to deviate from the traditional Commission methodology using average of monthly average

("AMA") rate base balances. This adjustment results in a $1.8 million reduction to the Company's revenue requirement.

c. **Non-labor Operations and Maintenance Escalation.** The Commission should reject the Company's use of an escalator for non-labor operations and maintenance ("O&M") expenses. This will reduce the Washington revenue requirement by $1.5 million.

d. **Pro-forma Energy Imbalance Market Costs.** While the Company has not proposed to include any pro-forma costs associated with the Energy Imbalance Market ("EIM"), the Company has forecast that these expenditures will produce material benefits in the rate period. I propose to include both the costs and the benefits of the EIM in this proceeding, thereby preventing a financial windfall to the Company. The costs associated with the EIM increase Washington revenue requirement by $394,087. The benefits are reflected in NPC, below.

2. **Net Power Cost Issues.** I propose several adjustments to the NPC calculated in the Company's Generation Regulation Initiative Decision ("GRID") model. Collectively, these adjustments result in a $16.7 million reduction to Washington revenue requirement. The adjustments have been accounted for in revenue requirement collectively and include the impact of revenue sensitive costs.

a. **Out-of-State Qualifying Facility Resources.** The Commission should continue to require the Company to allocate the costs of qualifying facility ("QF") resources on a situs-basis, in accordance with Order 05 in the Company's 2013 General Rate Case, Docket No. UE-130043 ("2013 GRC"). Removing costs associated with out-of-state QF resources in the Company's filing reduces NPC by $43.3 million on a Western Control Area ("WCA") basis, with $10.0 million allocated to Washington.

b. **Interregional EIM Dispatch Benefits.** The Commission should require the Company to include in NPC the interregional dispatch benefits expected in relation to its participation in the EIM. These benefits reflect reduced transactional friction between the Company and the California Independent System Operator ("Cal-ISO") resulting in a $4.0 million reduction to WCA NPC, with $913,257 allocated to Washington.

c. **Intraregional EIM Dispatch Savings.** The Commission should require the Company to model in GRID the intraregional dispatch savings expected in relation to its participation in the EIM. These savings represent the improved system dispatch that will result when the Company begins to use the Cal-ISO Security Constrained Economic Dispatch ("SCED") model, resulting in a

$12.4 million reduction to WCA NPC, with $2.9 million allocated to Washington.

d. **EIM Reserve Diversity Savings.** The Commission should require the Company to model in GRID the flexibility reserve savings expected in relation to its participation in the EIM. These reserve savings represent a reduction to load following reserve requirements associated with increased resource diversity across the EIM footprint, resulting in a $2.1 million reduction to WCA NPC, with $492,724 allocated to Washington.

e. **Within-hour EIM Dispatch Savings.** The Commission should require the Company to model in GRID the within-hour dispatch savings expected in relation to its participation in the EIM. These savings represent the value of dispatching resources on a sub-hourly time-scale, resulting in a $3.3 million reduction to WCA NPC, with $765,951 allocated to Washington.

f. **Network Integration and Transmission ("NT") Service.** The billing factor assumed by the Company for Bonneville Power Administration ("BPA") NT service is different than the actual billing factor in BPA's Open Access Transmission Tariff ("OATT"). Correcting for this error reduces WCA NPC by $1.4 million, with $315,506 allocated to Washington.

g. **Inter-hour Integration Costs.** The Commission should require the Company to remove inter-hour wind and load integration charges included in NPC outside of the GRID model. Removing these charges results in a $1.1 million reduction to WCA NPC, with $253,827 allocated to Washington.

h. **Chehalis Outage Rate.** The Commission should require the Company to remove a catastrophic outage that occurred at the Chehalis facility in late 2013. In addition to not being representative of normalized operations, [redacted]. This adjustment results in a $546,864 reduction to WCA NPC, with $129,491 allocated to Washington.

3. **Renewable Resource Tracking Mechanism.** The Commission should reject the Company's proposal for a renewable resource tracking mechanism ("RRTM") to track the market value associated with RPS resources. The mechanism is conceptually and structurally flawed and does not accurately isolate the costs associated with RPS resources.

4. **Deferral Requests.** The Commission should not grant deferred accounting treatment for the Company's consolidated deferral requests. Each request would bypass ratepayer safeguards and institute dollar-for-dollar recovery of Company costs contrary to the Commission's deferred accounting standards.

a. **Colstrip Unit 4 Outage Deferral.** The Commission should reject the Company's proposal for deferred accounting treatment related to an extended outage at Colstrip Unit 4. These outage costs are more appropriately recovered from the plant operator, rather than ratepayers.

b. **Hydro Deferral.** The Commission should reject the Company's proposal for deferred accounting treatment related to poor hydro conditions in 2014. Hydro conditions have not, in fact, been poor in 2014. The Company's power cost forecasts also represent median hydro conditions, so it would be inappropriate to grant a one-sided deferral for years with poor hydro conditions, while disregarding years with good hydro conditions.

c. **Merwin Fish Collector Deferral.** The Commission should not allow the Company to include in base rates any accrual related to return on rate base, interest, or depreciation associated with the Merwin Fish Collector deferred accounting petition.

Q. HAVE YOU PREPARED A TABLE TO SUMMARIZE BOISE'S OVERALL RECOMMENDATION?

A. Yes. The following table provides a summary of Boise's recommended adjustments to the Company's revenue requirement in this proceeding. In addition to adjustments that will be discussed in my testimony, this table includes an adjustment to reflect the revenue requirement impact of the cost of capital recommendation made by Mr. Gorman. Detailed revenue requirement calculations for these adjustments are contained in Exhibit No.___(BGM-3). Boise may also adopt additional adjustments proposed by other parties in this proceeding.

TABLE 1

Boise Integrated Revenue Requirement Summary

Company Proposed Revenue Deficiency	**$ 27,201,266**
Boise Adjustments:	
Cost of Capital (Sponsored by Mr. Gorman)	(6,446,948)
Pro-forma Capital Additions	(3,796,702)
EOP Rate Base	(1,844,255)
O&M Escalation	(1,511,448)
Energy Imbalance Market Costs	394,087
Net Power Costs	(16,732,141)
Total Adjustments	**(29,937,407)**
Adjusted Revenue Deficiency (Sufficiency)	**$ (2,736,141)**

II. REVENUE REQUIREMENT ISSUES

A. Pro-forma Capital Additions

Q. HOW HAS THE COMPANY PROPOSED TO ACCOUNT FOR ELECTRIC PLANT IN SERVICE IN THE TEST PERIOD?

A. The Company has proposed to include capital expenditures in rate base related to 30 different pro-forma capital additions in this proceeding.[1/] The Company argues that its proposal to include this long list of pro-forma capital additions, representing approximately $129 million in gross plant, is consistent with the Commission's Order 05 in the 2013 GRC.[2/] In Order 05, the Commission allowed the Company to include in rate

[1/] Exh. No.___(NCS-3) at 8.4.2-9.

[2/] Exh. No.___(NCS-1T) at 6:9-14.

base capital additions related to four major projects that were placed into service shortly after the test period, while excluding the Merwin Fish Collector project.[3/]

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. No. I disagree that the scope and breadth of the Company's proposal conforms to the Commission's Order 05 in the 2013 GRC. The Company has proposed to include all pro-forma projects with a budget in excess of $250,000 and initially planned to be placed in service between January 1, 2014, and March 31, 2015. The result is 30 different pro-forma projects that the Company has requested the Commission review for inclusion in rate base.[4/] In contrast, only five major capital additions were analyzed by the Commission in the 2013 GRC, and each had a capital budget in excess of $10 million. The Company's current proposal, however, results in only one project—the Merwin Fish Collector—with a capital budget of similar scope, i.e., exceeding $10 million. Thus, as a result of including such a large number of relatively small capital projects, I do not agree that the Company's proposal conforms to the Commission's Order 05 in the 2013 GRC.

Q. WHAT TREATMENT DO YOU RECOMMEND FOR THE PROPOSED PRO-FORMA CAPITAL ADDITIONS?

A. In recognition of the heightened burden that the Company must meet in order to include pro-forma capital additions in rate base, I recommend that the Commission reject all pro-forma capital additions proposed by the Company, with the exception of the Merwin Fish Collector. The Merwin Fish Collector is by far the largest capital addition that the Company is requesting in this proceeding. It has a capital budget of approximately $49.3

3/ WUTC v. PacifiCorp, Docket No. UE-130043, Order 05 at ¶¶ 186-209 (Dec. 4, 2013).

4/ Exh. No.___(NCS-1T) at 26:8-13.

million, which, if allowed by the Commission in rates, would provide the Company the opportunity to recover approximately 38 percent of the total capital additions requested in its filing. While Boise generally disagrees with the inclusion of any post-test-year capital addition in rate base, it is not contesting the inclusion of the Merwin Fish Collector in rate base in this proceeding.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. Removing all pro-forma capital additions, with the exception of the Merwin Fish Collector, results in an approximate $3.9 million reduction to revenue requirement.

Q. DID THE COMPANY UNIFORMLY APPLY THE CRITERIA USED TO DETERMINE WHICH PROJECTS TO INCLUDE IN RATE BASE?

A. No. Despite suggesting that it included in rate base all pro-forma projects with a budget in excess of $250,000, and to be placed in service between January 1, 2014, and March 31, 2015, it appears that the "bright-line" criteria formulated by the Company was not uniformly applied and that the Company applied subjective judgments to determine which pro-forma capital projects to include in rate base. For example, the Company has forecasted capital costs related to the EIM of nearly $15.8 million,[5/] which, despite meeting the "bright-line" criteria, have been excluded from rate base. Offering little explanation as to why the EIM capital costs should be afforded different treatment than other pro-forma capital projects, the Company suggests that the costs, and associated benefits, of the EIM are not known and measurable at this time.[6/] I will address the EIM-related capital costs below; however, the Company's proposal to exclude these costs,

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5/ Exh. No.___(BGM-4C) (the Company's Response to Boise Data Request ("DR") 5.4 (Rocky Mountain Power's Response to Wyoming Industrial Energy Consumers ("WIEC") DR 23.6)).

6/ Exh. No.___(GND-1CT) at 7:4-17.

which arguably better conform to the scope of pro-forma capital additions typically reviewed by the Commission, demonstrates that the Company does not view its proposal on pro-forma capital additions to be definitive.

Q. PLEASE STATE YOUR UNDERSTANDING OF THE COMMISSION'S POLICY REGARDING PRO-FORMA CAPITAL EXPENDITURES.

A. The Commission has traditionally adopted a policy to consider post-test-year capital additions on a case by case basis, stating that it has "recognized the limits imposed by the 'used and useful' and 'known and measurable' standards while exercising the considerable discretion those standards allow in the *context of individual cases*."[7/] This case by case analysis has provided the Commission with flexibility when evaluating these factors without being confined by "too rigid an approach" through a consistent, bright-line standard, which might prevent the Commission from considering the context of each individual adjustment.[8/]

Moreover, in the Company's 2013 GRC, the Commission reiterated its definition of the known and measurable standard applicable to capital additions, referring to an earlier order in a proceeding with Puget Sound Energy, Inc. ("PSE"):

> The known and measurable test requires that an event that causes a change in revenue, expense or rate base must be known to have occurred during, or reasonably soon after, the historical 12 months of actual results of operations, and the effect of that event will be in place during the 12-month period when rates will likely be in effect. Furthermore, the actual amount of the change must be measurable. This means the amount typically cannot be an estimate, a projection, the product of a budget forecast, or some similar exercise of judgment – even informed judgment – concerning future revenue, expense or rate base. There are

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7/ 2013 GRC, Order 05 at ¶ 198 (emphasis added).

8/ Id. at ¶¶ 198-99.

> exceptions, such as using the forward costs of gas in power cost projections, but these are few and demand a high degree of analytical rigor.[9/]

The Commission also states that the Company has the burden of proof to show that resources allocated to Washington are "used and useful for service in this state."[10/] This means that the Company must demonstrate "quantifiable" benefits to ratepayers in Washington for each and every resource to be included in rates.[11/]

Q. DO THE CAPITAL EXPENDITURES PROPOSED BY THE COMPANY SATISFY THESE COMMISSION STANDARDS?

A. No. My understanding is that the Company bears the burden of providing evidence necessary for the Commission to conclude that a pro-forma capital expenditure should be included in rate base. As a result of the scale of the Company's request and the lack of evidence concerning the proposed pro-forma project presented in the Company's filing, I disagree that the Company has provided the necessary evidence for the Commission to make an affirmative determination that each of the pro-forma projects proposed by the Company satisfy the known and measurable and used and useful standards. Therefore, it is not possible for the Commission to apply the necessary case by case review to determine whether the long list of capital additions is appropriately included in rate base in this proceeding.

Q. WHAT EVIDENCE HAS THE COMPANY PRESENTED?

A. The Company has divided testimony and exhibits supporting the proposed pro-forma capital projects. Of the 30 capital projects that the Company has proposed to include in

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9/ Id. at ¶ 205 (quoting WUTC v. PSE, Docket Nos. UE-090704 *et al.*, Order 11 ¶ 26 (Apr. 2, 2010)).

10/ WUTC v. PacifiCorp, Docket No. UE-050684, Order 04 at ¶ 49 (Apr. 17, 2006).

11/ Id. at ¶ 51.

rate base, five are supported in the testimony of three witnesses—Messrs. Vail, Tallman, and Ralston. The remaining 25 are supported in brief narrative descriptions included in an exhibit of Ms. Siores' testimony.[12/]

Q. DO THE 25 PROJECTS INCLUDED IN MS. SIORES' EXHIBIT SATISFY THE COMMISSION STANDARD FOR INCLUSION IN RATE BASE?

A. No. The narrative descriptions associated with the remaining 25 projects fall short of providing the Commission with the necessary information to determine whether these pro-forma projects satisfy the heightened burden to be included in rate base. In addition to being relatively small projects not warranting an exception to the Commission's traditional test period methodology, the capital budgets associated with and the timing of many of these projects is highly uncertain at this time. For example, the Yale Upper Rock Block Stabilization project was originally planned to be placed in service in October 2014 at a total cost of \$2.7 million.[13/] It is now planned to go into service in February 2015 at a total cost of \$6.2 million.[14/] Many of the other small projects follow a similar pattern, which the Company has made no effort to explain in testimony. Accordingly, I recommend that the Commission disregard the 25 projects supported only in Ms. Siores' exhibit.

12/ Exh. No.___(NCS-1T) at 6:1-8; Exh. No ___(NCS-3) at 8.4.4-9.

13/ Exh. No ___(NCS-3) at 8.4.2.

14/ Exh. No.___(BGM-4C) (the Company's 1st Revised Response to Public Counsel ("PC") DR 54, Attachment PC 54-1 1st Revised).

Q. DO YOU AGREE THAT THE FIVE PROJECTS DISCUSSED IN TESTIMONY BY OTHER WITNESSES MEET THE COMMISSION'S USED AND USEFUL AND KNOWN AND MEASURABLE STANDARDS?

A. Boise is not providing testimony to contest the inclusion of the Merwin Fish Collector in rate base; however, I do not agree that the following four projects meet the Commission's used and useful and known and measurable standards: 1) the Jim Bridger Unit 1 Cooling Tower Replacement Project; 2) the Union Gap Substation Upgrade; 3) the Selah Substation Capacity Relief; and 4) the Fry Substation Project.[15/]

Q. WHY DO YOU BELIEVE THAT THE JIM BRIDGER UNIT 1 COOLING TOWER REPLACEMENT PROJECT DOES NOT MEET THE COMMISSION'S USED AND USEFUL AND KNOWN AND MEASURABLE STANDARD?

A. Both the costs and timing of this project appear uncertain. In the Company's initial filing, it forecast the cost to replace the Jim Bridger Unit 1 cooling tower to be approximately $5.9 million.[16/] In response to PC DR 54, however, the Company indicated that its latest estimate to replace the cooling tower was only $2.2 million, or approximately 62 percent less than initially forecast.[17/]

Not only was the cost estimate materially different from the initial forecasts, the timing of the project was also materially different in PC DR 54. The Company changed the in service date for the Jim Bridger Unit 1 cooling tower from May 2014,[18/] as discussed in the direct testimony of Dana M. Ralson, to October 2014.[19/]

15/ See Exh. No ___(NCS-3) at 8.4.4, 8.4.6, and 8.4.9; Exh. No.___(RAV-1T); Exh. No.___(DMR-1T).

16/ Exh. No.___(DMR-1T) at 4:4.

17/ Exh. No.___(BGM-4C) (the Company's Response to PC DR 54, Attachment 54-1).

18/ Exh. No.___(DMR-1T) at 4:9.

19/ Exh. No.___(BGM-4C) (the Company's Response to PC DR 54, Attachment 54-1).

On September 25, 2014, the Company issued a revised response to PC DR 54, stating that "sorting errors result[ed] in a mismatch between certain projects and their in-service dates and plant-in-service amounts."[20/] Some of the Company's cost estimate variances, including those related to the Jim Bridger Unit 1 cooling tower, were updated.[21/] While the cost and timing of the Jim Bridger Unit 1 cooling tower project presented in the revised attachment more closely aligned with the Company's filing, this correction illustrates the uncertainty surrounding the ultimate costs that the Company is proposing to include in rate base. As a result of this continued uncertainty, I recommend that the Commission reject the Jim Bridger cooling tower capital addition.

Q. DO YOU HAVE SIMILAR CONCERNS WITH THE CAPITAL ADDITIONS SUPPORTED IN THE TESTIMONY OF MR. VAIL?

A. Yes. I have the similar concerns with all three proposed capital additions supported by the testimony of Mr. Richard A. Vail, all of which were scheduled to go into service after the Company filed its case: 1) the Union Gap Substation Upgrade; 2) the Selah Substation Capacity Relief; and 3) the Fry Substation Project.[22/]

Q. WHAT ARE YOUR SPECIFIC CONCERNS WITH THE UNION GAP SUBSTATION UPGRADE?

A. Mr. Vail suggested that the Union Gap substation upgrade project is a three-phase project, which will ultimately result in the installation of a high-voltage (230/115 kV) transformer in order to comply with certain North American Electric Reliability

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20/ Exh. No.___(BGM-4C) (the Company's 1st Revised Response to PC DR 54).

21/ See Exh. No.___(BGM-4C) (the Company's 1st Revised Response to PC DR 54, Attachment PC 54-1 1st Revised).

22/ Exh. No.___(NCS-3) at 8.4.4 and 8.4.9; Exh. No.___(RAV-1T).

Corporation ("NERC") standards.[23/] The $8.65 million capital project, however, only relates to the first phase of what is ultimately a three phase project. In testimony, Mr. Vail described the first stage as relocating the delivery-voltage portion of the substation in order to accommodate upgrades that will take place in phases two and three of the project.[24/]

The work Mr. Vail described in the first phase seems to be a preliminary step to make room in the substation in order to accommodate additional bus work and installation of high-voltage transformers at later phases in the project. While two delivery-voltage transformers are expected to be replaced as a part of the first phase of the project,[25/] these transformers may have remained in service had it not been necessary to move them. In addition, the replacement cost for these two transformers likely represents only a minor portion of the work performed in the first phase of the project. Accordingly, my concern with this project is that I disagree that it is appropriate to characterize it, as Mr. Vail does, as three distinct projects, which are used and useful when viewed independently. In my view, the Union Gap Substation Upgrade cannot be found to be known and measurable, nor used and useful, until the final phase of the project is completed in summer of 2015. Thus, the pro-forma capital cost of the Union Gap Substation Upgrade project should not be included in rate base in this proceeding.

In addition, Mr. Vail has categorized the capital associated with this preliminary phase in the Union Gap Substation Upgrade as Washington, situs-allocated distribution

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23/ Exh. No.___(RAV-1T) at 3:3-13.

24/ Id.

25/ Id.

costs. To the extent, however, that the work performed in the substation relates to making room for transmission assets, much of these capital costs are more properly categorized as transmission and allocated on a WCA basis.

Q. WHAT ARE YOUR SPECIFIC CONCERNS WITH THE SELAH SUBSTATION CAPACITY RELIEF PROJECT?

A. The cost estimates associated with this project are uncertain. The Selah Substation Capacity Relief project was expected to be placed in service in December 2013 at a total cost of $4.55 million.[26/] As of July 2014, however, the total expected cost of the project was updated to $4.94 million, approximately 9 percent higher than originally projected.[27/] Accordingly, the capital cost of project, which may not be placed into service at the time the hearing for this proceeding concludes, does not appear to be known with enough certainty to include it in rate base.

Q. WHAT ARE YOUR SPECIFIC CONCERNS WITH THE FRY SUBSTATION PROJECT?

A. Both the timing and costs of this project are uncertain. In the Company's initial filing, the Fry Substation Project was originally expected to be placed into service in December 2014, at a total cost of $6.38 million.[28/] While the Company has not made changes to its cost estimates since July, the expected in-service date has shifted at least two months, from December 2014 to February 2015.[29/] Thus, there is uncertainty surrounding when this facility will be placed in service, indicating that neither known and measurable nor used and useful standards can be met at this time.

26/ Id. at 7:15-17.

27/ Exh. No.___(BGM-4C) (the Company's Response to PC DR 54, Attachment 54-2).

28/ Exh. No.___(RAV-1T) at 8:14-23.

29/ Exh. No.___(BGM-4C) (the Company's Response to PC DR 54, Attachment 54-2).

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION RELATED TO PRO-FORMA CAPITAL ADDITIONS.

A. The Company's proposal to include 30 different pro-forma capital additions in rate base far exceeds the scope of the type of capital projects on which the Commission typically performs its case by case review. In addition to being relatively minor projects, the evidence suggests that much of the pro-forma capital costs presented in the Company's initial filing are too uncertain to be included in rate base at this time. With the exception of the Merwin Fish Collector project, removing these capital additions results in an approximate $3.8 million reduction to Washington revenue requirement.

B. End of Period Rate Base

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL TO USE EOP RATE BASE BALANCES IN THIS PROCEEDING?

A. No. The use of EOP balances results in a mismatch between revenues, which accrue ratably over the test period, and rate base, which, under the EOP method, is measured at the end of the test period. In addition, the Company's current practice of almost continuous rate cases mitigates the impact of regulatory lag and the need to deviate from the traditional Commission methodology using AMA rate base balances. Accordingly, I recommend the Commission reject the Company's proposal to use EOP rate base balances, resulting in a $1.8 million reduction to the Company's revenue requirement.

Q. WHY DO YOU BELIEVE IT IS APPROPRIATE FOR THE COMPANY TO USE AMA, RATHER THAN EOP BALANCES?

A. From an accounting perspective, it violates the matching principle to use averages for revenue items, but year-end balances for rate base items. Because revenues accrue ratably over the test year, the rate base, against which operating income is compared, should also reflect the ratable period over which revenues are measured.

Q. DO YOU HAVE ANY OTHER CONCERNS RELATED TO EOP RATE BASE?

A. Yes. In the 2013 GRC, the Commission provided the Company the opportunity to use EOP rate base in order to mitigate regulatory lag and what was described as a "current pattern of almost continuous rate cases."[30/] The facts are, however, that the use of EOP rate base has done little to assuage the frequency of the Company's rate filings. The Commission issued its final Order 05 in the 2013 GRC on December 4, 2013, approving the use of EOP rate base. Notwithstanding, less than five months later, the Company filed this general rate case. As a result of the Company's current pattern of continuous rate cases, I disagree that regulatory lag—a degree of which encourages utilities to operate efficiently—is a problem for the Company that is properly addressed through the EOP rate base methodology.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION RELATED TO EOP RATE BASE.

A. In recognition of the mismatch between EOP rate base and revenues, which are incurred ratably over the year, I recommend that the Commission require the Company to use AMA rate base balances when determining revenue requirement in this proceeding, resulting in a $1.8 million reduction to revenue requirement.

30/ 2013 GRC, Order 05 at ¶ 181 (quoting WUTC v. PSE, Docket Nos. UE-111048 and UG-111049 (*consolidated*), Order 08 at ¶ 507 (May 7, 2012)).

C. Non-labor O&M Escalation

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL TO ESCALATE NON-LABOR O&M COSTS USING IHS GLOBAL INSIGHTS ESCALATION FACTORS?

A. No. The use of O&M escalation factors does not conform to the Commission's known and measurable standard. I recommend that the Commission reject the Company's pro-forma O&M escalation adjustments, resulting in a $1.5 million reduction to the Company's revenue requirement.

Q. DOES THE APPLICATION OF NON-LABOR O&M ESCALATION CONFORM WITH THE COMMISSION'S USE OF A HISTORICAL TEST PERIOD?

A. No. While the Commission has taken some latitude with regard to the application of a historic test period, the Company's proposal to escalate non-labor O&M runs too far afield of what the Commission typically considers to conform to the known and measurable standard. With limited exception, the Commission has traditionally not allowed costs in revenue requirement that represent "an estimate, a projection, the product of a budget forecast, or some similar exercise of judgment – even informed judgment – concerning future revenue, expense or rate base."[31/] These escalation costs, however, are both an estimate and a projection, and, thus, should not be allowed in revenue requirement under the Commission's traditional rate making standard.

[31/] Docket Nos. UE-090704 *et al.*, Order 11 at ¶ 26.

D. Pro-forma Energy Imbalance Market Costs

Q. WHAT IS YOUR PROPOSAL REGARDING ENERGY IMBALANCE MARKET COSTS AND BENEFITS?

A. If the Commission determines that other major pro-forma capital additions should be included in revenue requirement—such as the Merwin Fish Collector—then EIM costs and associated benefits should also be reflected in revenue requirement.

Q. HAS THE COMPANY PROPOSED TO INCLUDE ANY COSTS ASSOCIATED WITH ITS PARTICIPATION IN THE EIM IN THIS PROCEEDING?

A. No. Despite meeting the criteria established by the Company to determine which pro-forma capital additions should be included in the rate base, the Company has proposed not to include any capital or operating costs associated with the EIM in this proceeding.[32/] Mr. Duvall provides the rational for excluding these costs and benefits, suggesting that:

> EIM costs and benefits are not yet sufficiently known and measurable to include in this filing. The EIM is new and key EIM components are still being developed and implemented.[33/]

Q. DO YOU AGREE WITH MR. DUVALL'S RATIONALE FOR EXCLUDING THE COSTS AND THE BENEFITS ASSOCIATED WITH THE EIM?

A. No. The Company has adopted a double standard for determining which pro-forma capital and operating costs to include in revenue requirement. While the Company proposes to include in rates a number of other post-test period capital projects, which have smaller capital budgets and will be placed in service at a later date than the EIM expenditures, it has not proposed that any costs or benefits of the EIM be afforded the same treatment.

32/ Exh. No.___(GND-1CT) at 7:7-9.

33/ Id.

Q. DO YOU BELIEVE THAT THE EIM COSTS ARE MORE APPROPRIATELY INCLUDED AS A PRO-FORMA ADJUSTMENT THAN THE CAPITAL ADDITIONS THAT YOU HAVE PROPOSED TO EXCLUDE ABOVE?

A. Yes. These costs are certain, as memorialized in the EIM Implementation Agreement entered into between the Company and Cal-ISO on April 30, 2013, and accepted by the Federal Energy Regulatory Commission ("FERC"), effective July 1, 2013.[34/] This agreement, as amended,[35/] created a firm commitment on the part of the Company to commit a known and measurable amount of capital into the implementation of the EIM. In addition, the EIM is operational as of October 1, 2014, and will be used and useful to ratepayers in the rate year, provided that the net benefits of the EIM are also reflected in rate year NPC.

Q. WHAT AMOUNT OF EIM COSTS HAS THE COMPANY INCURRED?

A. While Boise has issued forthcoming data requests for the final amount of capital committed to the EIM as of the October 1, 2014 "go-live" date, the latest capital estimate, as of June 2014, was that the Company would incur approximately $15.8 million in capital costs, inclusive of a $2.1 million start-up fee payable to the Cal-ISO.[36/] The Company also expects to incur an additional $3.0 million per year in additional O&M expenses, consisting of $1.4 million annually to the Cal-ISO in ongoing variable charges,

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34/ Cal. Indep. Sys. Operator Corp., 143 FERC ¶ 61,298 (2013).

35/ Letter Order Accepting CAISO Filing of Amendment to Implementation Agreement, FERC Docket No. ER14-1350 (Apr. 8, 2014).

36/ Exh. No.___(BGM-4C) (the Company's Response to Boise DR 5.4 (Rocky Mountain Power's Response to WIEC DR 23.6)).

as well as an additional $1.6 million annually related to additional headcount and information technology systems and support.[37/]

Q. WHAT IS THE IMPACT OF INCLUDING EIM CAPITAL AND OPERATING COSTS IN REVENUE REQUIREMENT?

A. Based on the cost estimates provided in June 2014, including EIM capital and operating costs in the test period produces an approximate $394,087 increase to Washington revenue requirement. This increase in revenue requirement is offset by benefits of approximately $5.1 million, reflected in the GRID modeling changes discussed below. I may provide an update at a later date in the proceeding if the Company provides actual cost data associated with implementing the EIM.

III. POWER SUPPLY COST ISSUES

Q. HAVE YOU REVIEWED THE COMPANY'S PROPOSED POWER SUPPLY COSTS IN THIS PROCEEDING?

A. Yes. I have reviewed the Company's testimony, exhibits, and workpapers relating to the proposed level of net power costs, as well as a significant volume of Company responses to data requests submitted by Boise, Commission Staff, Public Counsel, and other parties. I have also performed a detailed review of the Company's GRID modeling, which has been used by the Company to forecast the level of rate year power supply costs presented in the direct testimony of Mr. Duvall.

37/ Id.

Q. WHAT ARE THE RESULTS OF YOUR REVIEW?

A. In addition to addressing the Company's proposal to include costs related to out-of-state QF resources and discussing the net power cost benefits associated with the EIM, I have discovered several updates, corrections, and methodological changes that I propose be made to the Company's filing. The following table details the adjustments that I propose to the Company's filing, as well as a balancing adjustment that reflects the consolidated impact of all proposed adjustments. These values do not include the impact of revenue sensitive costs, so the subtotal differs slightly from the amount presented in Table 1, above.

TABLE 2
Net Power Cost Adjustments

	WCA	Washington
Filed NPC	**$ 568,782,271**	**$ 130,188,942**
Adjustments:		
Out-of-state QF Resources	(43,347,589)	(10,037,807)
Interregional EIM Dispatch Benefits	(3,956,084)	(913,257)
Intraregional EIM Dispatch Benefits	(12,425,964)	(2,934,523)
EIM Flexibility Reserve Diversity	(2,102,516)	(492,724)
Within-hour EIM Dispatch Benefits	(3,267,890)	(765,951)
BPA NT Service Calculations	(1,366,723)	(315,506)
Inter-hour Integration	(1,099,540)	(253,827)
Chehalis Outage	(546,864)	(129,491)
Balancing Adjustment	(428,314)	(101,356)
Total Adjustments	**(68,541,483)**	**(15,944,443)**
Adjusted NPC	**$ 500,240,788**	**$ 114,244,499**

A. Out-of-state Qualifying Facility Resources

Q. DID THE COMPANY RELY ON THE COMMISSION-APPROVED WCA METHODOLOGY IN DETERMINING NET POWER COSTS?

A. No. As in its 2013 GRC, the Company has proposed to modify the WCA methodology approved by the Commission in order to change the allocation of costs associated with QF resources located in other states within the WCA. Specifically, the Company proposes to include in rates all QF resources within the WCA, despite acknowledging that the Commission recently rejected the same proposal in Order 05 in 2013 GRC.[38/] In addition, Mr. Duvall suggests two alternatives to the long-standing Commission methodology for determining NPC attributable to QF resources in the WCA.[39/]

Q. WHAT IS YOUR RESPONSE TO THE COMPANY'S PROPOSALS?

A. I recommend that the Commission reject the Company's main proposal, as well as its alternative proposals, regarding out-of-state QF resources. This issue was recently (i.e., less than *five months* prior to the Company's filing) decided by the Commission, and the Company has not provided any new or compelling evidence to support vacating the prior Commission determination on this matter. Accordingly, I propose a $43.3 million reduction to WCA power costs, with $10.0 million allocated to Washington, to conform the Company's filing to the Commission-approved methodology.

Q. PLEASE EXPLAIN WHY THE COMPANY'S MAIN PROPOSAL SHOULD BE REJECTED.

A. I recommend that the Commission reject the Company's main proposal because it is not consistent with Commission-approved methodology. The Commission's WCA

38/ Exh. No.___(GND-1CT) at 2:7-16.

39/ Id. at 2:14-16.

methodology explicitly excludes the costs associated with QF resources located in Oregon and California, the other WCA states.[40] This approach is fair, as Washington, Oregon, and California have adopted different policies in establishing avoided cost rates for QF contracts. As the Commission explains: "Washington's policies are paid for by Washington taxpayers or ratepayers [and] … Oregon's and California's renewable energy policies should be paid for by the taxpayers and ratepayers of those states …."[41]

Conversely, the Company's proposal to include in NPC all QF resources throughout the WCA, including Oregon and California, would unfairly burden Washington ratepayers with funding the renewable energy policy choices made in other states. As the Commission recently stated, the inclusion of Oregon and California QF contracts results in NPC which "are significantly higher than would be the case if they were priced at Washington avoided cost rates."[42] The Commission methodology appropriately excludes Oregon and California QF costs on the principle that each state in the WCA should bear the costs of its own renewable energy policies.[43]

Q. DOES THE COMPANY OFFER ANY ACCEPTABLE REASON TO DEPART FROM ESTABLISHED WCA METHODOLOGY?

A. No. The Commission has repeatedly confirmed the principles supporting the approved WCA methodology, "absent a regionally negotiated alternative arrangement."[44] The

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40/ 2013 GRC, Order 05 at ¶ 110.

41/ Id. at ¶ 111.

42/ Id. at ¶ 113; accord at ¶ 98.

43/ Id.

44/ Id. at ¶¶ 111, 113.

Company points to no such "regionally negotiated alternative arrangement" in this proceeding, either in support of its main proposal or its alternative approaches.

Q. DO YOU HAVE ANY OTHER FUNDAMENTAL CONCERNS WITH THE COMPANY'S PROPOSAL?

A. Yes. The Company does not explain how it would be just, reasonable, or legally permissible for the Commission to require that out-of-state QF resource costs be included in Washington rates, given that the Commission has never approved these out-of-state QF contracts and that the Commission does not possess any jurisdiction over those resources. The Company has made no effort in direct testimony to demonstrate why it would be appropriate for the Commission to approve such contracts.

Q. WHAT RATIONALE DOES THE COMPANY OFFER IN SUPPORT OF ITS REQUEST THAT THE COMMISSION RECONSIDER ITS REJECTION OF THE COMPANY'S PROPOSAL IN THE 2013 GRC?

A. Mr. Duvall states that one reason for reconsideration is that QFs from other WCA states physically deliver power to meet Washington load, which directly benefits Washington customers.[45/] This misses the point. As the Commission has explained, situs allocation under the approved WCA methodology concerns only the assignment of costs, and has nothing to do with the physical flow of power over state boundaries.[46/] The Commission's methodology is just and reasonable because Washington ratepayers retain responsibility for paying for all power used, including power attributed to Oregon and

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45/ Exh. No.___(GND-1CT) at 8:18-23.

46/ 2013 GRC, Order 05 at ¶ 98.

California QF resources, but such power is priced at market rates, rather than the higher avoided cost rates in those states.[47]

The Company also offers no explanation as to why Washington ratepayers would receive any direct benefit from paying for Oregon or California QF power at rates higher than market prices. Mr. Duvall seems to imply that the Commission's methodology is unfair in stating that Washington customers only pay for QF resources located in Washington.[48] In approving the WCA methodology, however, "the Commission recognized that the Company assumed any risk of under-recovery of costs due to states approving different methodologies."[49] Certainly, if the other WCA states had adopted the same methodology as Washington, situs-assigning the costs of QF resources, there would be no question regarding the fairness of the Washington methodology. Accordingly, to the extent the Company is indeed under-recovering the costs associated with out-of-state QF resources, it may be more appropriate for it to seek additional rate relief from the other WCA states, not from Washington ratepayers.

Q. WHAT IS YOUR RESPONSE TO MR. DUVALL'S CONTENTION THAT HIGHER AVOIDED COST PRICES IN OTHER WCA STATES ARE NOT EXCESSIVE?

A. It is not the issue, nor is Mr. Duvall's statement that avoided cost prices in Oregon and California do not necessarily violate the Public Utilities Regulatory Policies Act ("PURPA") because they exceed market rates.[50] The Commission's WCA methodology is not premised upon a determination of "excessive" avoided cost rates or an analysis of

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47/ Id.

48/ Exh. No.___(GND-1CT) at 8:27-9:2.

49/ 2013 GRC, Order 05 at ¶ 81.

50/ Exh. No.___(GND-1CT) at 11:4-6.

how other states apply PURPA. In fact, the Commission acknowledges that each state has significant leeway in implementing PURPA and may set avoided cost rates at higher or lower levels to reflect state renewable energy policies.[51] Certainly, another state could establish avoided cost rates that are lower than market prices, and Washington ratepayers would be foreclosed from receiving the lower cost power associated with those rates under the WCA method.

Q. WHAT ARE THE COMPANY'S ALTERNATIVE APPROACHES TO THE WCA METHODOLOGY?

A. Mr. Duvall describes two approaches the Company has examined to address costs associated with Oregon and California QF resources. The first is called a "load decrement" approach, and would reduce the loads assumed for Oregon and California jurisdictional allocation factors based on the level of QF output in each state. The second is labeled a "Washington re-pricing" approach and would include Oregon and California QF resources in NPC, but re-price them at Washington avoided cost rates.[52]

Q. PLEASE EXPLAIN WHY YOU DO NOT SUPPORT THESE ALTERNATE COMPANY APPROACHES.

A. As a threshold matter, it does not appear that the Company has met the burden prescribed by the Commission in the 2013 GRC for proposed changes to the WCA methodology. Specifically, the Company is required to demonstrate that any proposed change more closely aligns cost allocation with causation, and to do so through a detailed and persuasive showing.[53] In that light, I would find it difficult to support any change to the

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51/ 2013 GRC, Order 05 at ¶ 102.

52/ Exh. No.___(GND-1CT) at 11:20-12:5.

53/ 2013 GRC, Order 05 at ¶ 94.

Commission's approved methodology given the lack of discussion in Mr. Duvall's testimony as to how each alternative approach more closely aligns cost allocation with causation.

In addition, by proposing several alternative allocation methodologies, it appears that the Company is not representing that any single methodology results in the most equitable allocation of costs between jurisdictions. It appears that the only reason why the Company believes that these options are reasonable is because they result in more NPC allocated to Washington ratepayers in a manner that is directionally consistent with the Company's initial proposal to include all out-of-state QF resources in Washington NPC—increasing costs assigned to Washington ratepayers.

Q. NOTWITHSTANDING, DO THE ALTERNATIVE METHODOLOGIES RESULT IN A FAIR JURISDICTIONAL COST ALLOCATION?

A. No. Both the "load decrement" and "Washington re-pricing" approaches result in an unfair jurisdictional cost allocation that is inconsistent with the principles of cost causation established by the Commission in its WCA allocation methodology.

Q. WHAT SPECIFIC CONCERNS DO YOU HAVE WITH THE LOAD DECREMENT APPROACH?

A. The load decrement approach would increase Company revenue requirement by $5.9 million. Under this proposal, the Company proposes to reduce the load forecast for the other WCA states by an amount equal to output of QF resources located within those states. This results in a reduction to other states' jurisdictional allocation factors and an increase to Washington's jurisdictional allocation factors. The increase in Washington allocation factors ultimately causes an increase to the amount of revenue requirement—

including O&M expenses, capital costs, taxes, and all other revenue requirement items—allocated to Washington ratepayers.

In justifying this change, Mr. Duvall claims that those resources "are deemed to serve customers in those states, consistent with the situs treatment ordered by the Commission in the 2013 Rate Case."[54/] But this statement is not an accurate representation of the end results of Mr. Duvall's proposal. What Mr. Duvall fails to discuss is why the proposed "load decrement" allocation of QF resources located in other WCA states should cause an increase in the allocation of non-NPC revenue requirement items to Washington. For example, under Mr. Duvall's treatment, Washington would bear a greater portion of the cost associated with the WCA transmission system, yet QF resources located in other states do not cause those other states to utilize a smaller portion of the transmission system, nor do they cause Washington to utilize a greater portion of the transmission system. The end result of the "load decrement" approach is inconsistent with the principles of cost causation, does not result in a fair allocation of WCA system costs, and should be rejected.

Q. DO YOU HAVE SIMILAR CONCERNS WITH THE "WASHINGTON RE-PRICING" APPROACH?

A. Yes. Mr. Duvall claims that, by increasing revenue requirement by $7.7 million as a result of re-pricing Oregon and California QF contracts at Washington avoided cost rates, "the impact of differences in individual state commission approaches to determining avoided cost prices" will be removed.[55/]

[54/] Exh. No.___(GND-1CT) at 12:11-13.

[55/] Id. at 13:22-14:3.

I disagree with this proposal. The WCA methodology was designed to allow for differences in each state's avoided cost pricing and renewable energy policy, while still fairly allocating cost burdens between those states. The "Washington re-pricing" approach would not be fair because Washington ratepayers would still bear the costs of other states' renewable energy policies, despite being based on the avoided cost rates approved by the Washington Commission. The problem with the Company's proposal is that avoided cost pricing is only one aspect of a state's overall renewable energy policy. Had the Washington renewable energy policy been in place in other states, for example, it is possible that many out-of-state QF contracts would not have been executed in the first place, or that more QF contracts would have been executed. It is impossible to know how the various aspects of Washington's energy policy would have impacted other states, had the Washington Commission retained jurisdiction over out-of-state QF resources.

To illustrate, standard QF contracts in Washington were once limited to a term of five years. Currently, they are limited to ten years. For non-standard QF resources, Washington utilizes a request for proposal process to determine the need, as well as the avoided cost rate, for those resources. In contrast, standard contracts in Oregon are limited to a term of twenty years and non-standard QF contracts are negotiated using the published rate as the starting point, rather than a request for proposal process. These particular differences in each state's policy towards QF resources—not to mention its overall renewable energy policy—would have had an impact on the quantity and type of QF resources procured in others states. Accordingly, the Company's "Washington re-pricing" proposal falls short of isolating the costs solely attributable to Washington's renewable energy policies and should be rejected.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION RELATED TO OUT-OF-STATE QF RESOURCES.

A. I recommend that the Commission reject the Company's proposals to include out-of-state QF resources in Washington NPC. The Commission's current jurisdictional allocation methodology is fair, just, reasonable and in the public interest. This results in a $43.3 million reduction to WCA power costs, with $10.0 million allocated to Washington.

<u>B. EIM Power Cost Benefits, Generally</u>

Q. HOW DO YOU PROPOSE TO QUANTIFY EIM BENEFITS IN THE TEST PERIOD?

A. As discussed above, I propose to reflect both the costs and benefits of the EIM in the Company's revenue requirement. While the costs of joining and participating in the EIM were described above, the benefits are derived from a reduction in overall NPC. In a proceeding before the Oregon Public Utilities Commission ("OPUC"), the Company argued that a study performed by Energy and Environmental Economics, Inc. ("E3"),[56/] which quantified the NPC benefits of the EIM, demonstrated that its decision to join the EIM was prudent.[57/] I propose to use the same E3 study, attached as Exh. No.___(BGM-5), to quantify the NPC impacts of the EIM in the rate period. The benefits are discussed as an individual modeling adjustment below, which collectively support including EIM

56/ <u>See</u> Exh. No.___(BGM-5) (PacifiCorp-ISO Energy Imbalance Market Benefits, Energy and Environmental Economics, Inc. (Mar. 13, 2013)). A copy of the E3 Report can also be found at http://www.caiso.com/Documents/PacifiCorp-ISOEnergyImbalanceMarketBenefits.pdf.

57/ <u>See</u> Exh. No.___(BGM-6) at 24:21-24.

benefits in NPC of $21.8 million on a WCA basis, with $5.1 million allocated to Washington.

Q. WHY SHOULD THE E3 STUDY BE USED TO ESTABLISH EIM BENEFITS IN THE TEST PERIOD?

A. The Company relied on the E3 study when it decided to join the EIM and has relied on the study results as evidence that its decision to join the EIM was prudent.[58/] Given that the Company believes the E3 study is sufficient to support the prudence of its decision to join the EIM, it should also be sufficient to establish the level of EIM benefits for ratemaking. Just as the Company relies on the 2012 Wind Integration Study to capture the wind integration costs modeled in GRID, the E3 study is an appropriate starting point to determine how test period NPC will be impacted by the operational changes associated with the EIM.

Q. WILL YOU PROVIDE AN OVERVIEW OF THE E3 STUDY?

A. The E3 study was issued jointly by the Company and the Cal-ISO on March 13, 2013. It was commissioned to examine the benefits of a potential EIM between the Company and the Cal-ISO. The study, which developed a range of benefits based on several uncertain parameters, evaluated benefits attributable to the following categories:

> 1. Interregional dispatch savings, by realizing the efficiency of combined 5-minute dispatch, which would reduce "transactional friction" (e.g., transmission charges) and alleviate structural impediments currently preventing trade between the two systems;
>
> 2. Intraregional dispatch savings, by enabling PacifiCorp generators to be dispatched more efficiently through the [Cal-

58/ Id.

ISO's] automated system (nodal dispatch software), including benefits from more efficient transmission utilization;

3. Reduced flexibility reserves, by aggregating the two systems' load, wind, and solar variability and forecast errors; and

4. Reduced renewable energy curtailment, by allowing [Balancing Authorities] to export or reduce imports of renewable generation when it would otherwise need to be curtailed.[59]

Q. WHAT RANGE OF BENEFITS DID THE E3 STUDY FORECAST FOR THE COMPANY?

A. The range of benefits forecast for the Company was $10.5 million to $54.4 million in 2012 dollars, represented in Table 3, below.[60]

TABLE 3

PacifiCorp EIM Benefits in E3 Study

Table 6. Attribution of EIM benefits to PacifiCorp in 2017 (million 2012$)

Benefit Category	Low transfer capability: Low Range	Low transfer capability: High Range	Medium transfer capability: Low Range	Medium transfer capability: High Range	High transfer capability: Low Range	High transfer capability: High Range
Interregional dispatch	$7.0	$5.5	$11.2	$8.9	$11.2	$8.9
Intraregional dispatch	$2.3	$23.0	$2.3	$23.0	$2.3	$23.0
Flexibility reserves	$1.2	$6.1	$3.2	$14.9	$3.9	$22.5
Renewable curtailment	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total benefits	**$10.5**	**$34.6**	**$16.7**	**$46.8**	**$17.4**	**$54.4**

Note: Attributed values may not match totals due to independent rounding.

Q. DID THE E3 STUDY INCLUDE ALL OF THE EXPECTED BENEFITS ASSOCIATED WITH THE EIM?

A. No. The E3 study was performed on an hourly basis and excluded within-hour dispatch benefits.[61] The within-hour dispatch benefits, which represent reserve savings and market optimization resulting from participation in sub-hourly markets, have been

[59] Exh. No.___(BGM-5) at 6-7.

[60] Id. at 35.

[61] Id. at 37.

demonstrated to be material. For example, a study performed by National Renewable Energy Laboratory ("NREL") included within-hour dispatch benefits and forecast PacifiCorp benefits of $180 million,[62/] more than three times the amount of benefits forecast in the E3 study. While it was performed to analyze an EIM that encompassed the entire western interconnection, the NREL study is an indication that the inter-hour dispatch benefits likely represent a material portion of the EIM benefits the Company will be capable of achieving.

Q. ARE THE E3 STUDY BENEFITS REPRESENTATIVE OF BENEFITS THAT WILL BE ACHIEVED IN THE RATE PERIOD?

A. Yes. Members of the Southwest Power Pool Regional Transmission Organization ("SPP") have participated in an EIM since February 2007. Following the implementation of its EIM, the SPP commissioned a study to determine the benefits achieved in the first year of operations.[63/] According to the report, the first-year benefits associated with the SPP EIM were approximately 20 percent higher than the benefits estimated by the studies performed prior to the start of the market.[64/] This suggests that the benefits achieved in the rate period could be even greater than the benefits presented in the E3 study.

62/ Examination of Potential Benefits of an Energy Imbalance Market in the Western Interconnection, NREL (Mar. 2013). For the $180 million figure, see NREL/Plexos Analysis of the Proposed EIM in the Western Interconnection: Individual BA Results, NREL at 39 (July 24, 2012). Copies of these reports are available online at http://westernenergyboard.org/energy-imbalance-market/documents/.

63/ SPP, Market Monitoring Unit and External Market Advisor, Report to SPP Board of Directors/Members Committee, Estimation of Net Trade Benefits from EIS Market at 1 (Apr. 22, 2008). A copy of the report is available at http://www.spp.org/publications/EIS%20Trade%20benefit%20report.pdf.

64/ Id.

Q. BASED ON THE RANGE PRESENTED IN THE E3 STUDY, HOW HAVE YOU DETERMINED THE LEVEL OF BENEFITS TO APPLY IN THE RATE PERIOD?

A. I have used the E3 study as a starting point to determine how to modify the Company's GRID modeling of NPC to reflect the operational benefits that will accrue in the rate period as a result of joining the EIM. The modeling has been modified to capture each of the benefits categories presented in the E3 study. My analysis also includes an adjustment to account for within-hour dispatch benefits which, as discussed above, were excluded from the E3 study.

<u>C. Interregional EIM Dispatch Savings</u>

Q. HOW DO YOU PROPOSE TO MODEL THE INTERREGIONAL DISPATCH SAVINGS ASSOCIATED WITH THE EIM IN THE TEST PERIOD?

A. The level of interregional dispatch savings expected in the rate period can be derived directly from the E3 study. Because the range of EIM benefits presented in the E3 study for each benefit category is sensitive to several key assumptions, the amount attributable to the test period can be ascertained by selecting the assumptions that most accurately represent what is known about the test period at this time. In addition, because the E3 study benefits were representative of the Company's entire system—both WCA and Eastern Control Area ("ECA")—I propose to allocate the interregional dispatch savings in proportion to the loads of the WCA and ECA. The result is an approximate $4.0 million reduction to WCA NPC, with $913,257 allocated to Washington.

Q. WHAT ARE THE STUDY PARAMETERS THAT YOU RELIED ON TO ARRIVE AT THIS LEVEL OF BENEFITS?

A. Interregional Dispatch Savings in the E3 study were sensitive to two key variables: EIM transfer capability and hydro contribution to flexibility reserves.

Q. WHAT ASSUMPTION DID YOU RELY ON FOR EIM TRANSFER CAPABILITY IN THE TEST PERIOD?

A. PacifiCorp has several interconnections and contract transmission rights with the Cal-ISO that can potentially be utilized for EIM activity. Transmission transfer capability limits the amount of imbalance energy that can flow between the Company and the Cal-ISO and impacts the amount of benefits that will be achieved. The E3 study presented a range of benefits based on three different potential interchange capabilities between the Company and the Cal-ISO, specifically 100 Megawatts ("MW"), 400 MW, and 800 MW.[65/] While the EIM transfer capability was not known at the time of the E3 study, the Company subsequently stated that it "currently has long-term contract wheeling rights of 331 MW northbound and 432 MW southbound with PacifiCorp Transmission" to facilitate EIM transfers, and that it is currently in the process of negotiating additional transfer capability with BPA.[66/] Accordingly, the 400 MW medium transfer capability assumption, which falls close to the Company's current southbound ownership rights, best represents the amount of transfer capability to assume in the test period.

65/ Exh. No.___(BGM-5) at 20.

66/ Exh. No.___(BGM-6) at 27:13-22.

Q. WHAT LEVEL OF HYDRO CONTRIBUTION TO FLEXIBILITY RESERVES DID YOU ASSUME?

A. In the E3 study, flexibility reserve savings and intraregional dispatch savings benefits are both sensitive to the percent of Company hydro capacity that will be capable of providing regulation and load following reserves. The E3 study analyzed both a 12 percent and 25 percent level of hydro contribution to flexibility reserves.[67/] Because the GRID model assumes approximately 25 percent of hydro contribution to reserves, it would be inconsistent to assume a lower level of hydro reserve capability for purposes of the E3 study than is reflected in base NPC in the GRID model. Therefore, the 25 percent of hydro contribution to flexibility reserves and, thus, the low estimate for interregional dispatch savings, is assumed for this component of the EIM.

Q HOW DID YOU CALCULATE THE ADJUSTMENT TO NPC TO REFLECT INTERREGIONAL DISPATCH SAVINGS?

A. In reference to Table 3, I used the $11.2 million value included under the medium transfer capability, low-range column for interregional dispatch benefits as an offset to NPC. This system-wide benefit, originally stated in 2012 dollars, was inflation adjusted to the test period, allocated to the WCA in proportion to load, and allocated to Washington on the Control Area Generation West ("CAGW") allocation factor, as detailed in Table 4 below.

67/ Exh. No.___(BGM-5) at 21.

TABLE 4
Calculation of Washington Allocated Interregional Dispatch Benefits
($millions)

E3 Study Benefits (2012$)	11.20
Adjust to Test Period $	11.89
WCA Load %	33.28%
WCA Test Period Benefits $	3.96
Washington CAGW Factor	23.08%
Washington Allocated Benefits $	0.91

D. Intraregional EIM Dispatch Savings

Q. WHAT ARE INTRAREGIONAL DISPATCH SAVINGS?

A. Intraregional dispatch benefits represent the improved dispatch optimization that results from the Company utilizing the Cal-ISO SCED model. The Company's current dispatch practices are largely manual, often involving issuance of manual dispatch orders to request a plant to increase or decrease output. As a result of deploying the Cal-ISO SCED model on the Company's system, plant dispatch will now be automated and optimized by the model. As a result, the Company's system is now capable of operating more efficiently, reducing overall NPC.

Q. HOW WERE INTRAREGIONAL DISPATCH SAVINGS CALCULATED IN THE E3 STUDY?

A. The intraregional dispatch benefits reported in the E3 study were calculated based on the total amount of benefits achieved by Cal-ISO when it initially implemented its SCED model, prorated for the Company's load.[68/] In calculating the range of benefits, the low

[68/] Exh. No.___(BGM-5) at 23-24.

estimate in the E3 study assumed that only 10 percent of these intraregional benefits would be achieved by the Company.[69] The high estimate assumed that 100 percent of these intraregional benefits would be achieved by the Company. Based on the high estimate, the total amount of potential intraregional dispatch benefits was calculated to be $23 million for the Company's entire system.[70]

Q. HOW DO YOU PROPOSE TO REFLECT INTRAREGIONAL DISPATCH SAVINGS IN THE GRID MODEL?

A. The GRID model contains assumptions and constraints that are designed to reflect the fact that in actual operations the Company has historically not been capable of optimizing its system to the degree that would otherwise be calculated in GRID. Market caps, for example, tie the maximum amount of sales assumed in a particular market hub to historical averages, incorporating into GRID the Company's historical, sub-optimal operations that resulted in those historical average sales. Once the Company deploys the Cal-ISO model, however, the historical averages used to develop market caps are no longer relevant. Because the Cal-ISO model is not subject to market caps, the Company will have the ability to optimize its system in actual operations in a manner that is consistent with how the GRID model optimizes its system in the absence of market caps. Accordingly, I view the value associated with the relaxation of market caps to be an accurate proxy for the benefit that the Company will achieve when it begins to operate its system using the Cal-ISO model.

69/ Id. at 24.

70/ Id.

Q. WHAT IS THE VALUE ASSOCIATED WITH THE RELAXATION OF MARKET CAPS IN THE GRID MODEL?

A. Relaxing market caps in the GRID model reduces WCA power cost by approximately $12.4 million, with $2.9 million allocated to Washington. I propose to use this level of cost reduction to be a proxy for the intraregional dispatch benefits that will be achieved from utilizing the Cal-ISO SCED model. Alternatively, I propose the market cap methodology adopted by the OPUC, discussed by Mr. Duvall, be used to account for the intraregional benefits that will accrue as a result of the EIM.[71/] Using the Oregon market cap methodology results in an approximate $4.4 million reduction to WCA power costs, with approximately $1.0 million allocated to Washington.

E. EIM Reserve Diversity Savings

Q. WHAT ARE THE FLEXIBILITY RESERVES DIVERSITY BENEFITS ASSOCIATED WITH THE EIM?

A. The flexibility reserves in the E3 study represented the load following reserve savings associated with "aggregating the two systems' load, wind, and solar variability and forecast errors."[72/] It should be noted that these reserve savings, which are representative of having a more diverse set of resources upon which to hold reserves, are distinct from the reserve savings that will accrue to the Company as a result of moving to a sub-hourly market and scheduling paradigm.

71/ Exh. No.___(GND-1CT) at 33:1-6.

72/ Exh. No.___(BGM-5) at 7.

Q. DID THE E3 STUDY QUANTIFY THE RESERVE SAVINGS THAT WILL BE ACHIEVED AS A RESULT OF THE EIM?

A. Yes. In addition to quantifying a dollar figure associated with these reserve savings, the E3 study also quantified the reduction to reserves in MW resulting from the Company's participation in the EIM, as reproduced in Table 5, below:[73]

TABLE 5
Reserve Savings Associated with Additional Resource Diversity in E3 Study

Table 3. Estimated Total Minimum Reserve Holdings under the EIM in 2017

PacifiCorp-ISO Transfer Capability	Minimum Reserve Holdings (MW)
Standalone (no EIM)	2,011
100 MW	1,932
400 MW	1,687
800 MW	1,583

Using this data, the benefits associated with this reduced reserve requirement can be incorporated into the Company's GRID modeling, capturing the rate year benefits of this EIM component. The E3 study calculated reserve savings for each EIM transfer scenario—100 MW, 400 MW, and 800 MW—and, for reasons discussed above, the 400 MW scenario, and, thus, 324 MW of flexibility reserve savings, best represents the reserve savings that can be achieved in the rate period.

Q. HOW DID YOU QUANTIFY THE RESERVE REDUCTIONS ATTRIBUTABLE TO THE WCA IN THE TEST PERIOD?

A. The following table details how the reserve reductions presented in the E3 study have been modeled in the test period. The reserve savings were pro-rated in proportion to the amount of reserves required under the no EIM transfer capability scenario, which is

[73] Id. at 26.

consistent with how the E3 study attributed reserve savings between the Company and the Cal-ISO.[74/]

TABLE 6
Calculation of WCA Reserve Savings from E3 Study

	Reserve Requirement (MW)		
	PacifiCorp	Cal-ISO	Total
No EIM Transfer Capability	608	1,403	2,011
400 MW EIM Transfer Capability	510	1,177	1,687
Reserve Savings	98	226	324
WCA Load %	33.28%		
WCA Reserve Savings	33		

Q. WHAT IS THE IMPACT OF MODELING THESE RESERVE SAVINGS IN THE GRID MODEL?

A. Modeling this level of reserve savings in the GRID model results in a $2.1 million reduction to WCA power costs, with $492,724 allocated to Washington. This amount represents a conservative estimate of the flexibility reserve savings that will result from combining the Company's system with the Cal-ISO through the EIM.

<u>F. Within-hour EIM Dispatch Benefits</u>

Q. HOW HAVE YOU QUANTIFIED THE WITHIN-HOUR DISPATCH BENEFITS ASSOCIATED WITH THE EIM?

A. I quantified these benefits based on a sensitivity performed in the Company's 2012 Wind Integration Study that analyzed the regulating reserve savings associated with 30-minute balancing.[75/] Because the EIM is a five-minute market, the 30-minute balancing reserves represent a conservative estimate of within-hour dispatch benefits that will be achieved as a result of joining the market. The 30-minute balancing reserves calculated in the 2012

[74/] <u>See</u> <u>id</u>. at 34 ("Benefits were allocated to PacifiCorp and ISO in proportion to their standalone need, resulting in a roughly 30/70 split, respectively.").

[75/] <u>See</u> PacifiCorp, 2013 Integrated Resource Plan, Volume II, Appendix H at 122-23 (Apr. 30, 2013).

Wind Integration Study were modeled in GRID using the same methodology employed by the Company to model reserves for load and wind in its filing.

Q. WHAT AMOUNT OF WCA RESERVE SAVINGS DID THE 2012 WIND INTEGRATION STUDY ASSOCIATE WITH 30-MINUTE BALANCING?

A. The 2012 Wind Integration Study calculated that the WCA regulation reserve requirement would decline by approximately 30 percent as a result of moving to 30-minute balancing.[76] Moving to 5-minute balancing, as is accomplished in the EIM, will likely result in an even greater level of reserve savings.

Q. DO THE WITHIN-HOUR DISPATCH BENEFITS OVERLAP WITH FLEXIBILITY RESERVE DIVERSITY?

A. No. The E3 study was clear when it stated: "Production simulation analysis [was] modeled at [an] hourly level, omitting potential benefits of sub-hourly dispatch (other studies indicate that these benefits could be substantial)."[77] In addition, because the various EIM benefit components have been modeled in GRID, the final balancing adjustment detailed in Table 2 removes any overlaps between components.

Q. WHAT IS THE IMPACT OF MODELING THE RESERVE REDUCTIONS ATTRIBUTABLE TO 30-MINUTE BALANCING PRESENTED IN THE 2012 WIND INTEGRATION STUDY?

A. Modeling the approximate 30 percent reduction to regulation reserves in the GRID model study resulted in a $3.3 million reduction to WCA NPC, with $765,951 allocated to Washington. This amount represents a conservative provision for the savings associated with within-hour EIM dispatch benefits.

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[76] Id. at 123.

[77] Exh. No.___(BGM-5) at 37.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION TO INCLUDE EIM BENEFITS IN BASE NPC.

A. As a component of the Company's NPC after it joins the EIM in October 2014, EIM benefits are appropriately included in this proceeding. Using conservative assumptions from the same study the Company uses to justify its participation in the EIM, I recommend that approximately $21.8 million in WCA EIM benefits be reflected in NPC in the test period in this proceeding, with $5.1 million allocated to Washington.

__G. Network Integration Transmission Service__

Q. PLEASE PROVIDE AN OVERVIEW OF HOW THE COSTS ASSOCIATED WITH BPA NT SERVICE ARE INCLUDED IN POWER COSTS.

A. The Company services several load pockets throughout Oregon and Washington using BPA NT service. NT Service provides the Company with the ability to serve these load pockets from designated network resources, without having to purchase a fixed amount of point-to-point transmission capacity. The wheeling costs associated with the BPA NT service required to serve these load pockets are included as a cost component of the Company's power costs. The Company has proposed to include approximately $[redacted] in power costs associated with NT service in the test period.[78/]

Q. HOW DID THE COMPANY CALCULATE THE COSTS FOR BPA NT SERVICE IN THE TEST PERIOD?

A. The Company used the non-coincident peak for each load pocket, and applied those peaks against BPA's current rates for network transmission and associated ancillary services.

78/ Confidential Workapers of Mr Duvall available in the company's filing as follows: "CD.4 WA UE-14_Confidential Workpapers (PACMay2014)\A. Duvall\NPC Workpapers CONF\Attach NPC WorkPapers -3 CONF\WAw_Wheeling CONF.xlsx"

Q. WHAT IS WRONG WITH THE COMPANY'S CALCULATION?

A. BPA NT service is not billed based on a customer's non-coincident peak load. The billing factor for NT service is the customer's Network Load on the hour of the Monthly Transmission System Peak Load, as those terms are defined in BPA's OATT.

Q. DOES THE COMPANY AGREE THAT NT SERVICE IS NOT BILLED BASED ON A CUSTOMER'S NON-COINCIDENT PEAK LOAD?

A. Yes. In response to Boise DR 10.5, the Company agreed that that the billing factor for NT Service provided by BPA is the customer's Network Load on the hour of the Monthly Transmission System Peak Load,[79/] not a customer's non-coincident peak load.

Q. WHY DOES THE COMPANY USE THE NON-COINCIDENT PEAK TO CALCULATE THE COST ASSOCIATED WITH BPA NT SERVICE?

A. The Company claims that, under its calculation, "[t]he non-coincident peak ("NCP") load and coincident peak ("CP") are assumed to be equal."[80/]

Q. IS THAT AN ACCURATE ASSUMPTION?

A. No. The load coincident to the time of transmission peak will almost always be less than non-coincident peak load. Thus, the Company's calculation overstates the billing factor and related costs associated with BPA NT service reflected in NPC.

Q. HOW DO YOU PROPOSE TO CALCULATE THE LOAD COINCIDENT TO THE TIME OF TRANSMISSION PEAK FOR PURPOSES OF CALCULATING BPA NT SERVICE COSTS?

A. BPA publishes the monthly transmission peak hour as far back as 2007.[81/] Accordingly, I propose to use the average of the four hourly loads in each month that correspond to the

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79/ Exh. No.___(BGM-4C) (the Company's Response to Boise DR 10.5).

80/ Exh. No.___(BGM-4C) (the Company's Response to Boise DR 10.6).

81/ Available at: http://www.bpa.gov/transmission/Reports/Pages/TTSL.aspx.

transmission peak load hours that occurred in that month in the four years 2010 to 2013. This time period is the same period that the Company uses to determine outage rates and other GRID model parameters.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW YOUR CALCULATION WORKS?

A. Yes. BPA's January transmission peaks in 2010 through 2013 occurred in the following hours: 01/02/2013 HE19, 01/17/2012 HE18, 01/21/2011 HE18, and 01/11/2010 HE19. To estimate transmission coincident peaks for January 2015, I used the average load for each load pocket on the day and hour in 2015 corresponding to those four transmission peaks. Thus, the January 2015 coincident peak for each load pocket would be estimated based on the average load in the four following hours: 01/02/2015 HE19, 01/17/2015 HE18, 01/21/2015 HE18, and 01/11/2015 HE19.

Q. WHAT IS THE IMPACT ON NPC OF USING THIS METHODOLOGY?

A. Using the network load coincident to the time of transmission peak results in an approximate $1.4 million reduction to WCA NPC, with $315,506 allocated to Washington.

<u>H. Inter-hour Integration Costs</u>

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR ADJUSTMENT RELATED TO INTER-HOUR INTEGRATION.

A. The Company has proposed a new, hourly wind shaping methodology in this proceeding, which results in an approximate $646,614 increase to power costs on a WCA basis. These costs are similar in nature to an inter-hour integration charge of approximately $693,190 that the Company includes in NPC, outside of the GRID model. Because both reflect costs that are representative of inter-hour variations in wind output, the costs associated with inter-hour wind integration are currently being double-counted in the Company's NPC modeling. In addition, the Company has included in its filing a new NPC charge of approximately $406,345 labeled "inter-hour load integration." In addition to double-counting the costs already reflected in the GRID model associated with the use of an hourly load forecast, this charge was neither included in the Company's prior filing, nor documented as a modeling change in the current rate filing. Accordingly, I also recommend the Commission require the Company to remove the inter-hour load integration charge from NPC.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION ON NPC?

A. Collectively, the impact of removing the double-counting inter-hour wind and load integration charges results in a $1.1 million reduction to WCA NPC, with $253,827 allocated to Washington.

Q. WHAT IS INTER-HOUR WIND INTEGRATION?

A. Inter-hour wind integration represents the system costs associated with the hour-to-hour variability in wind output. As a result of this variability, Company resources must dynamically respond to the hour-to-hour changes in wind output. Company resources must ramp up and down, and commit on and off, resulting in an overall increase to system costs.

Q. HOW IS INTER-HOUR WIND INTEGRATION DOUBLE-COUNTED IN THE GRID MODEL?

A. As a result of the Company's new hourly wind shaping methodology, the GRID model now includes the hour-to-hour variability associated with actual wind profiles. Thus, the costs associated with this hour-to-hour variability, which were previously included in a separate inter-hour wind integration charge, are now reflected in the GRID model dispatch. While it was appropriate for the Company to include a separate inter-hour wind integration cost to account for the hour-to-hour variability of wind using its prior wind shaping methodology, because the hour-to-hour variability of wind is now included in GRID, this inter-hour charge is no longer appropriate.

Q. HOW DID THE COMPANY SHAPE WIND IN PRIOR GENERAL RATE CASE PROCEEDINGS?

A. In the 2013 GRC, the Company shaped wind using what is known as a monthly diurnal forecast. A monthly diurnal forecast uses the same daily wind profile for each day in a given month. The Company developed the monthly diurnal forecasts based on the median ("p50") output expected in six, four-hour blocks in each day and month and, thus, the forecast lacked the variability of wind seen in actual operations. As discussed in the direct testimony of Mr. Duvall, wind generation forecasting shaped over flat four-hour blocks did not capture the actual variability associated with wind generation on the Company's system.[82/]

Q. HOW HAS THE COMPANY PROPOSED TO MODEL WIND IN THIS PROCEEDING?

A. The Company modified its modeling methodology in this proceeding to shape wind based on a dynamic, hourly profile derived from actual wind output in 2012.[83/] While the average amount of energy for each resource remained the same as under the prior methodology, the new hourly wind shaping "uses the actual 2012 energy output data

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82/ Exh. No.___(GND-1CT) at 25:20-26:2.

83/ Id. at 26:3-11.

from the Company's owned and purchased wind facilities to shape hourly wind generation profiles."[84/] The result, demonstrated in Mr. Duvall's testimony, is a dynamic wind profile that introduces costs into the GRID model that are representative of inter-hour integration costs. Accordingly, it is no longer appropriate to include inter-hour integration costs as a separate charge outside of the GRID model.

Q. WHY SHOULD THE COMPANY'S PROPOSED INTER-HOUR LOAD INTEGRATION CHARGE BE REMOVED FROM NPC?

A. The inter-hour load integration charge is a new NPC line item that was not included in NPC calculated in the 2013 GRC. The Company has offered no testimony on the calculation or purpose of this new NPC item. The Company, by including this charge, has not conformed to the Commission rule requiring utilities to document methodological changes to revenue requirement calculations;[85/] therefore, the costs proposed related to inter-hour load integration should not be allowed in this proceeding. In addition, similar to inter-hour wind integration, the inter-hour costs associated with load are already reflected in the hourly system balancing calculated by the GRID model. Thus, they are also double-counted in the Company's GRID modeling.

Q. PLEASE EXPLAIN HOW INTER-HOUR LOAD INTEGRATION IS ALREADY REFLECTED IN THE GRID MODEL SYSTEM BALANCING.

A. Similar to inter-hour wind integration, the GRID model includes a load profile with hour-to-hour variability. When the GRID model calculates dispatch, resources must respond to this variability by ramping up and down and cycling on and off. This creates additional system costs in GRID that represent the inter-hour cost of integrating load. If

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84/ Id. at 26:5-6

85/ WAC § 480-07-510(3)(e)(i).

the Company now includes inter-hour load integration as a separate charge outside of the model, these inter-hour costs will be double-counted.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. Because they result in double-counting costs that are already included in GRID model dispatch, these inter-hour wind and load integration charges should be removed from NPC. This adjustment results in a $1.1 million reduction in WCA NPC, with $253,827 allocated to Washington.

I. Chehalis Outage Rate

Q. PLEASE DESCRIBE YOUR ADJUSTMENT RELATED TO THE OUTAGE RATE OF CHEHALIS.

A. In late 2013, Chehalis generating station, the Company's 500 MW combined cycle combustion turbine located in Chehalis, Washington, experienced a catastrophic outage that [redacted]. In addition to not being representative of plant operations in the rate period, [redacted] I proposed to eliminate this outage from the Company's outage rate calculations used in the GRID model. Removing this major outage from the four-year base period results in a $546,864 reduction to WCA power costs, with $129,491 allocated to Washington.

Q. WHAT WAS THE EXTENT OF THE OUTAGE THAT OCCURRED AT CHEHALIS IN LATE 2013?

A. [redacted][86/] [redacted]

86/ Exh. No.___(BGM-7C) at 7.

[redacted][87] [redacted][88]

Q. WHAT WAS THE CAUSE OF THE OUTAGE?

A. The root cause analysis associated with the Chehalis outage, provided in response to WIEC DR 1.40 in Wyoming Docket No. 20000-447-EA-14, is attached as Exh. No.___(BGM-7C). [redacted][89]

Q. WHY DO YOU BELIEVE THAT THIS IS EVIDENCE OF [redacted]?

A. [redacted][90]

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[87] Id. at 3.
[88] Id. at 7.
[89] Id.
[90] Id.

[redacted][91] [redacted]

[redacted].[92]

It appears from the root cause analysis that, [redacted] the major failure of the plant in late 2013 [redacted] the catastrophic outage.

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[91] Id. at 10.
[92] Id. at 11.

Q. WOULD YOU EXPECT AN OUTAGE OF THIS NATURE TO HAPPEN IN THE RATE PERIOD?

A. No. An outage of this nature should not be expected to occur in the rate period. So, in addition [redacted], the Company should take steps to avoid this sort of outage in the future.

IV. RENEWABLE RESOURCE TRACKING MECHANISM

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S PROPOSED RRTM.

A. The Company has proposed an RRTM to provide recovery for the actual costs associated with resources used to meet the Washington RPS. According to Mr. Duvall, the Company's NPC is subject to significant variability driven in part by variations in generation attributable to RPS resources.[93/] The Company maintains that such variability is beyond its control and, because the Washington Energy Independence Act requires customers to bear the costs of prudent RPS compliance, it is necessary to adopt an RRTM providing dollar-for-dollar true-up of the market value of RPS resources included in Washington rates.[94/] Notably, the Company proposes no deadbands, sharing bands or earnings test in its proposed RRTM.[95/]

Q. DO YOU RECOMMEND THAT THE COMMISSION APPROVE THE PROPOSED RRTM?

A. No. The Company has not demonstrated that the year-to-year variability in RPS resource output is so extraordinary as to justify a power cost recovery mechanism that is limited

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93/ Exh. No.___(GND-1CT) at 38:20-22.

94/ Id. at 38:19-39:4

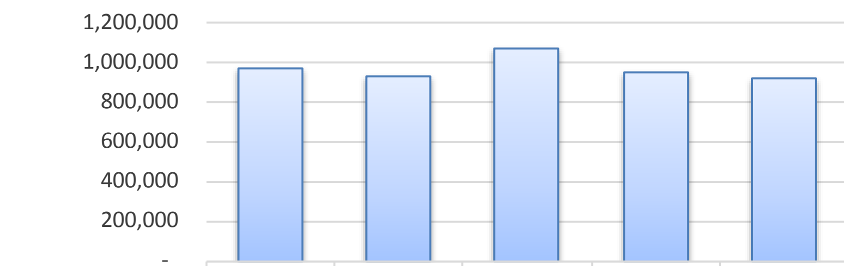
95/ Id. at 39:19-21.

solely to RPS resources. In addition, while it proposes to track only the actual costs of RPS resources, the Company has not demonstrated that it is possible to accurately "carve-out" the actual costs and benefits associated with RPS resources. The mechanism is also structurally flawed, capturing changes in market prices typically reflected in a comprehensive power cost mechanism that are unrelated to renewable resource compliance. Finally, the mechanism lacks the safeguards, such as sharing bands and deadbands, historically required by the Commission in a power cost adjustment mechanism. For these reasons, the Commission should reject the Company's proposed RRTM.

Q. DOES THE YEAR-TO-YEAR VARIABILITY IN RENEWABLE RESOURCE OUTPUT WARRANT EXTRAORDINARY RATE TREATMENT?

A. No. The year-to-year variability of RPS resource output is not so significant as to warrant extraordinary rate treatment. Figure 1, below, demonstrates the actual output from Company-owned wind resources between 2009 and 2013. As can be seen from the figure, the changes in wind output remain relatively stable year-to-year. The relative standard deviation of the year-to-year variation in wind output is approximately 6 percent.

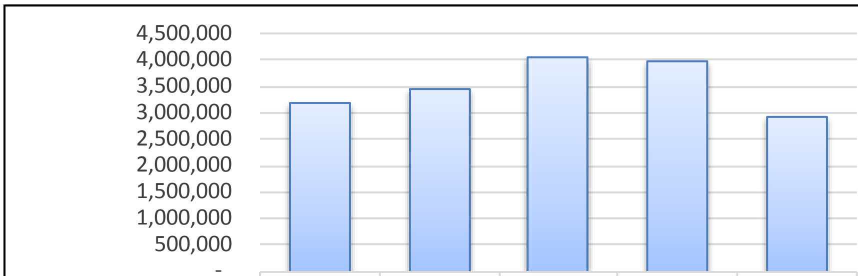
Figure 1
Actual Company-owned Wind Generation (MWh)
2009 – 2013



	2009	2010	2011	2012	2013
WCA Owned Wind Generation (MWh)	970,972	932,244	1,073,363	948,282	919,274

A threshold question for determining whether the variability associated with RPS resources is so extraordinary to warrant extraneous rate treatment is whether RPS generation is more or less variable than other power cost items. As a comparator, Figure 2, below, demonstrates the actual west side hydro generation between 2009 and 2013.

Figure 2
Actual West Side Hydro Generation (MWh)
2009 – 2013



	2009	2010	2011	2012	2013
WCA Hydro Generation (MWh)	3,195,324	3,462,802	4,060,597	3,976,914	2,914,852

As can be noted from a comparison of the two figures, wind output between 2009 and 2013 has not been any more variable, year-to-year, than hydro output over the same period. In contrast to wind output, with a relative standard deviation of 6 percent, the relative standard deviation of hydro output was 14 percent, indicating that hydro output was more than twice as variable, year-to-year, as wind output. Accordingly, I disagree with the Company that the variability of RPS generation warrants extraneous rate treatment, when RPS output is no more variable than other components of net power costs, such as hydro generation.

Q. DO YOU BELIEVE THAT IT IS POSSIBLE TO ACCURATELY "CARVE-OUT" THE ACTUAL POWER COSTS ATTRIBUTABLE SOLELY TO RPS RESOURCES?

A. No. The Company's RPS resources operate as an integrated part of its overall supply portfolio. If RPS output is less than expected, the Company will rebalance its position by increasing thermal resource output or making market purchases. If RPS output is greater than expected, the Company will rebalance its overall position by decreasing thermal resource output or making market sales. The costs associated with varying levels of RPS output are the result of complex, offsetting interactions between various types of resources within its portfolio. Simply comparing RPS output to market prices, as the Company has done, ignores the true system costs associated with varying levels of RPS resource output, thereby producing an economic windfall to the utility. As a result, I do not agree that it is possible to isolate and separately track the actual costs associated with RPS resources.

Q. DOES THE COMPANY BELIEVE THAT IT IS POSSIBLE TO ACCURATELY CARVE-OUT THE COSTS ASSOCIATED WITH RPS RESOURCES?

A. No. The Company has taken the position, in a recent proceeding before the OPUC, that it is not possible to independently isolate the net power costs attributable only to RPS resources. In that proceeding, the Company argued for a power cost adjustment mechanism ("PCAM") in Oregon that covered all power costs items, stated as follows:

> The Company has shown that it is impossible to isolate, quantify, and accurately forecast the NPC impacts of [RPS] resources and that the only way to fully recover the variable costs of [RPS] compliance is with a dollar-for-dollar PCAM.[96/]

Thus, even the Company has agreed that it is not possible to accurately isolate the actual NPC solely attributable to RPS resources.

Q. DO YOU HAVE ANY OTHER CONCERNS WITH THE COMPANY'S PROPOSAL TO ISOLATE RPS RESOURCE POWER COSTS IN THE RRTM?

A. Yes. Portfolio diversification is one of the fundamental principles relied on by utilities in order to develop a least-cost, least-risk resource portfolio. In general, a diversified portfolio will have less risk than the aggregate risk associated with each asset in the portfolio, when viewed separately. For purposes of utility planning, this means that a utility will benefit from procuring power supplies that are dependent on many different fuel and resource types. Because the risks associated with different fuel types are based, in whole or in part, on independent risk variables, the utility's overall risk profile will decline as a result of the offsetting nature of each of the fuel or resource types in its portfolio. For example, in a diversified resource portfolio such as the Company's, low wind output in any given year may be offset by higher hydro generation or lower gas prices resulting in more stability in overall NPC. My concern with the Company's proposal is that, by attempting to isolate only the variability associated with renewable

96/ In re PacifiCorp, Request for a General Rate Revision, OPUC Docket No. UE 246, PacifiCorp's Post-Hearing Brief at 36 (Nov. 7, 2002).

output, the Company is ignoring the fact that its overall system is benefiting as a result of the diverse nature of all the resources in its portfolio.

To illustrate my concern, assume the Company's resource portfolio to be the equivalent of a diversified investment portfolio consisting of Fortune 500 stocks. Under this scenario, the RRTM mechanism would be similar to the Company requesting a deferral mechanism for losses, or gains, associated with a single stock holding, even though its overall investment portfolio resulted in a gain for the period.

Q. PLEASE EXPLAIN HOW MARKET PRICES ARE INCORPORATED INTO THE COMPANY'S RRTM PROPOSAL.

A. In the Company's proposed RRTM, variability in market prices—despite having little to do with the Company's obligation to comply with RPS requirements—may produce a deferral regardless of how accurately the Company forecasts the output from RPS resources. Variances in market price have broader NPC implications than just those related to RPS resources, and, accordingly, are not appropriate for dollar-for-dollar recovery through a stand-alone mechanism, such as that proposed by the Company.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW MARKET PRICES IMPACT THE COMPANY'S PROPOSED RRTM?

A. Table 7, below, provides a simplified illustration to demonstrate that the Company's recovery under the RRTM would not solely be related to its ability to accurately forecast the energy output of RPS resources. Even if the Company perfectly forecasts such output, it may still collect dollar-for-dollar recovery as a result of inaccurately forecasting the market price for that energy.

Table 7
Market Price Impact on RRTM

	Forecast	Actual	Deferral
RPS Output (MWH)	100	100	-
Market Price ($/MWH)	35	30	(5)
RPS Market Value ($)	3,500	3,000	(500)

Q. WHY IS THE IMPACT OF MARKET PRICES ON THE PROPOSED RRTM CONCERNING?

A. Under the Company's proposal, if market prices are lower in actual operation than in the Company's forecast, the proposed RRTM mechanism would result in a larger deferral. This is concerning because lower market prices may result in a reduction to overall NPC, yet the Company would receive extraordinary recovery through its proposed RRTM, notwithstanding incurring lower overall power costs. On the other hand, if market prices are higher in actual operation than in the Company's forecast, the proposed mechanism may result in an increased refund to customers, despite the fact that the Company's overall power costs may be higher as a result of higher market prices. This structural flaw in the Company's proposal produces results that are not reasonable, suggesting that the RRTM should be rejected.

Q. IS THE ABSENCE OF DEADBANDS AND SHARING BANDS IN THE PROPOSED RRTM ALSO A CONCERN?

A. Yes. The absence of deadbands and sharing bands would place Washington customers at significant risk and is contrary to Commission policy concerning minimum requirements for cost recovery mechanisms like the proposed RRTM. The Commission states that deadbands and sharing bands "are critically important elements that provide an incentive for the Company to manage carefully its power costs and that protect ratepayers in the event of extraordinary power cost excursions that are *beyond the Company's ability to control*."[97/] The Company proposes the RRTM on the very basis that RPS resource variations account for "a high degree of variability" in NPC which are "largely outside of the Company's control."[98/] Thus, based on the Company's own testimony, deadbands and sharing bands are critically important to any recovery mechanism which could adequately protect ratepayers from costs variability outside of Company control.

Q. PLEASE SUMMARIZE WHY THE COMMISSION SHOULD REJECT THE COMPANY'S PROPOSED RRTM.

A. The proposed RRTM should be rejected because: 1) the Company has not demonstrated that RPS output is any more variable than other power cost variables; 2) it is not possible to accurately track the actual power costs solely attributable to RPS resources; 3) it is structurally flawed, providing the Company the opportunity to true up the impact of market prices; and 4) it lacks the design elements that the Commission has historically required in power cost recovery mechanisms.

97/ 2013 GRC, Order 05 at ¶ 170 (emphasis added).

98/ Exh. No.___(GND-1CT) at 38:19-22.

V. DEFERRAL REQUESTS

Q. HAVE YOU REVIEWED THE COMPANY'S PETITIONS FOR DEFERRED ACCOUNTING WHICH HAVE BEEN CONSOLIDATED INTO THE GRC?

A. Yes, I have reviewed the Company's petitions originally filed under Docket Nos. UE-131384 ("Colstrip Outage"), UE-140094 ("Declining Hydro"), and UE-140617 ("Merwin Fish Collector").

Q. PLEASE SUMMARIZE YOUR ASSESSMENT OF THE COMPANY'S DEFERRAL REQUESTS.

A. I have two major concerns with the Company's requests. First, I disagree that the Company should be provided dollar-for-dollar recovery of the costs associated with any deferral relating to NPC. As discussed in the context of the RRTM, the Company's failure to develop a PCAM that conforms to the explicit direction the Commission has given the Company in the past is the reason that the Company does not currently have a tracking mechanism in place to cover NPC.[99/] Had such a mechanism been in place, it is likely that the costs the Company has requested to defer would fall within the traditional safeguards—deadbands and sharing bands—that the Commission requires to be in place for power cost mechanisms. Both the Colstrip Outage and Declining Hydro deferred accounting requests would allow the Company to bypass the Commission's requirement to include design elements such as deadbands and sharing bands in its PCAM.

Second, based on my understanding of the Commission's deferred accounting standards, the Company does not appear to have met its burden in demonstrating that deferred accounting is justified in any of its requests.

99/ See 2013 GRC, Order 05 at ¶¶ 169-170.

Q. PLEASE ELABORATE ON THE STANDARDS WHICH THE COMMISSION HAS APPLIED TO DEFERRED ACCOUNTING REQUESTS.

A. Since at least 2002, the Commission has consistently required that a utility requesting deferred accounting must demonstrate that costs are "extraordinary" and "due to factors beyond the Company's control."[100] Merely alleging "extraordinary" costs is not a sufficient basis for deferred accounting under the Commission's standards.[101] I disagree that the Company has demonstrated that the events in question are, in fact, extraordinary and due to factors beyond the Company's control, and recommend that the Commission reject the Colstrip Outage and Declining Hydro deferral petitions and not allow a return on rate base, interest, or special depreciation in relation to the Merwin Fish Collector.

A. Colstrip Outage Deferral

Q. HOW DOES THE COMPANY ATTEMPT TO JUSTIFY THE COLSTRIP OUTAGE DEFERRAL?

A. The Company argues that, unlike other Washington utilities, it currently has no mechanism to recover unexpected fluctuations in NPC.[102] I disagree, however, that the Company's lack of a PCAM is a reasonable basis to receive deferred accounting treatment for a single aspect of its overall power costs. It certainly could be argued that the fact that the Company does not have a PCAM is the result of its own refusal to

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100/ E.g., In re PacifiCorp, Docket No. UE-020417, 3rd Suppl. Order at ¶ 5 (Sept. 27, 2002); WUTC v. PacifiCorp, Docket No. UE-050684, Order 04 at ¶ 305 (Apr. 17, 2006) (combining both standards in affirming that deferred accounting is "warranted in extraordinary *circumstances*") (emphasis added); see also WUTC v. PacifiCorp, Docket No. UE-100749, Order 10 at ¶ 21 & n.19 (Aug. 23, 2012) (quoting the 2002 order to explain the purpose of deferred accounting).

101/ In re PacifiCorp, Docket No. UE-020417, 6th Suppl. Order at ¶ 29 (July 15, 2003) (finding insufficient nexus between causation and cost to justify deferred accounting, even if the "extraordinary" nature of costs might "arguably" provide a rationale for deferral).

102/ Docket No. UE-131384, PacifiCorp's Petition for an Accounting Order at ¶ 6 (July 26, 2013) ("Colstrip Petition").

incorporate deadbands and sharing bands into the mechanism proposed in the 2013 GRC. Notwithstanding, the Company is not requesting a power cost mechanism in this proceeding which would cover the outage for which it has sought recovery through a stand-alone deferral. Therefore, it is not valid to suggest that the lack of a PCAM is an extraordinary circumstance warranting deferred accounting for the Colstrip Outage.

Q. DO YOU AGREE THAT THE COMPANY WOULD RECEIVE EXTRAORDINARY RECOVERY ASSOCIATED WITH THE COLSTRIP OUTAGE IF IT DID HAVE A PCAM?

A. No. While it is impossible to know what the particular design elements of a PCAM might be for the Company, it is likely that the Company would not receive any extraordinary recovery associated with the Colstrip Outage if it did have one. If the Company had a PCAM that was structured similarly to PSE's, the entire amount that the Company is requesting to defer under its Colstrip Outage petition would fall within the $20 million deadband and be ineligible for recovery. In addition, under PSE's mechanism, any amount in excess of the deadband is subject to 50/50% sharing on up to $40 million in NPC variance.

Q. DO YOU AGREE THAT THE COSTS ASSOCIATED WITH THE COLSTRIP OUTAGE QUALIFY FOR DEFERRED ACCOUNTING?

A. No. First, I disagree that the additional power costs alleged by the Company can be accurately quantified in order to qualify for deferred accounting. The Company's deferral initially proposed to cover the estimated costs associated with purchasing replacement power ranging from $9 to $12 million on a total-company basis.[103/] The Company, however, has not updated this estimate based on costs that it actually incurred.

[103/] Id. at ¶ 8.

Specifically, it has not demonstrated what replacement power was actually acquired in order to qualify for deferral. As discussed in relation to the RRTM, as a result of the complex interactions between resources in the Company's resource portfolio, it is not possible to "carve-out" the power costs attributable solely to a single resource.

In addition, the Company has not demonstrated that costs related to the Colstrip Outage qualify as "extraordinary." Initially, the Company estimated repair costs at $3 to $4 million, with replacement power costs ranging from $9 to $12 million on a total-company basis.[104/] The Company's estimated capital repair costs on a Washington-allocated basis, however, are just $305,646, which do not appear to be "extraordinary," particularly since $4.8 million of initially reported repair costs had already been purchased prior to the outage.[105/] Moreover, the Company has received $2.6 million from insurance proceeds to offset Colstrip Outage costs, with a deductible of just $250,000.[106/] Finally, the Company has acknowledged that any increased costs for replacement power will be offset by a reduction in Colstrip fuel costs,[107/] a factor omitted from the Colstrip Petition.

Q. HAS THE COMPANY DEMONSTRATED THAT THE COLSTRIP OUTAGE COSTS WERE DUE TO FACTORS BEYOND ITS CONTROL?

A. No. When the Company filed the Colstrip Petition, it stated only that the cause of the outage was "under investigation."[108/] After the completion of that investigation, the

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104/ Id.

105/ Exh. No.___(BGM-4C) (UE-131384, the Company's Responses to PC DRs 11, 13).

106/ Exh. No.___(BGM-4C) (the Company's Response to Boise DR 7.9; UE-131384, the Company's Response to WUTC DR 9).

107/ Exh. No.___(BGM-4C) (UE-131384, the Company's Response to PC DR 9).

108/ Colstrip Petition at ¶ 4.

Company indicated that: "There was no incontrovertible cause of failure identified."[109/] More specifically, based upon information obtained in confidential discovery, the Company asserts [redacted][110/] Based upon my review of information supplied by the Company, however, I do not agree with this assessment.

For instance, the root cause analysis on the Colstrip failure found that [redacted][111/] In fact, the analysis notes that [redacted][112/] Such findings as to [redacted] cannot be reasonably reconciled with the ultimate conclusion in the analysis that [redacted][113/] In other words, a [redacted]

On the contrary, indications are that the operator was responsible. As the Company explains, Colstrip "failure was most likely … caused during the previous outage by rotor insertion, skid pan damage, or air gap baffle installation."[114/]

[redacted], the root cause analysis found the Colstrip failure [redacted]—bolstering the

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109/ Exh. No.___(BGM-4C) (UE-131384, the Company's Responses to PC DR 2 and WUTC DR 5).

110/ Exh. No.___(BGM-4C) (the Company's Response to Boise DR 4.8, Confidential Attachment Boise 4.8).

111/ Exh. No.___(BGM-4C) (the Company's Response to Boise DR 4.3, Confidential Attachment at 5).

112/ Exh. No.___(BGM-4C) (the Company's Response to Boise DR 4.3, Confidential Attachment at 25).

113/ Exh. No.___(BGM-4C) (the Company's Response to Boise DR 4.3, Confidential Attachment at 46).

114/ Exh. No.___(BGM-4C) (UE-131384, the Company's Response to WUTC DR 5).

conclusion that [redacted][115] Indeed, [redacted] in the root cause analysis stated [redacted][116] Further still, the analysis found that [redacted] the Colstrip failure *was* [redacted][117]

[redacted], the most probable and logical conclusion as to the cause of the Colstrip failure is error attributable to the plant operator as a result of repair work done at the time of the prior outage. It follows that the cost of repairs and replacement power are more appropriately recovered from the plant operator, not from ratepayers through this deferral application.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING THE COLSTRIP PETITION?

A. I recommend that the Commission reject the Company's petition for deferred accounting of Colstrip Outage costs because the Commission's deferred accounting standards have not been satisfied.

[115] Exh. No.___(BGM-4C) (the Company's Response to Boise DR 4.3, Confidential Attachment at 26, 33).

[116] Exh. No.___(BGM-4C) (the Company's Response to Boise DR 4.3, Confidential Attachment at 35).

[117] Exh. No.___(BGM-4C) (the Company's Response to Boise DR 4.3, Confidential Attachment at 45).

B. Declining Hydro Deferral

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR RECOMMENDATION REGARDING THE COMPANY'S PROPOSAL TO DEFER COSTS RELATED TO DECLINING HYDRO CONDITIONS

A. The Company initially filed its petition related to declining hydro conditions on January 17, 2014. At that time hydro conditions were forecast to be below average for the calendar year, raising concerns among many Northwest utilities regarding hydro availability in 2014. Fortunately, the Northwest experienced higher than average spring precipitation, which has resulted in Northwest hydro conditions that are about normal. Notwithstanding the normal hydro conditions that have occurred in 2014, the Company is still proposing to defer extraordinary costs associated with declining hydro generation in the 2014. I recommend that the Commission reject the Company's proposal.

Q. NOTWITHSTANDING THE NORMAL HYDRO CONDITIONS THAT ACTUALLY OCCURRED IN 2014, WHY SHOULD THE COMPANY'S PROPOSAL BE REJECTED?

A. The deferred accounting proposal is one-sided. The Company forecasts hydro output in the GRID model based on median generation of a historical period. Accordingly, half of the time hydro generation is expected to be lower than the Company's forecast, and half of the time it is expected to be higher. In this case, the Company is seeking deferred accounting for costs associated with hydro generation that it originally expected to be below the median forecast; yet, the Company has not made similar proposals when hydro generation has been greater than the median. In 2011 and 2012 for example, when the spring run-off was well above the median, the Company made no effort to return the savings attributable to the higher than average hydro conditions in those years.

Q. DO YOUR CONCERNS REGARDING THE APPLICATION OF A DEADBAND AND SHARING BANDS TO THE COLSTRIP OUTAGE APPLY EQUALLY TO THE DECLINING HYDRO DEFERRAL?

A. Yes. If the Company had a PCAM, it would likely contain deadbands and sharing bands that would restrict the amount of NPC that the Company would be eligible to defer in relation to the hydro conditions. The likely result is that the Company would receive no extraordinary recovery for the costs incurred in relation to hydro conditions in 2014.

C. Merwin Fish Collector Deferral

Q. WHAT IS THE COMPANY'S JUSTIFICATION FOR DEFERRING MERWIN PROJECT COSTS?

A. The Company initially requested deferred accounting only as an alternative to a proposed tariff rider to recover Merwin Fish Collector costs.[118/] The stated basis for deferred accounting was that "customers continue to benefit from emission-free, low-cost hydropower generation" as a result of the Company's investment in the Merwin Fish Collector.[119/]

Q. PLEASE PROVIDE SOME BACKGROUND ON THIS DEFERRAL.

A. When consolidating the Merwin Project docket with the Company's GRC, the Commission explicitly made "no finding as to whether the amount of the revenue requirement the Company seeks to recover is prudent."[120/] Indeed, the Commission stated: "we share ICNU's and Public Counsel's concerns about limiting the use of deferred accounting of investment costs between rate cases," explaining that it granted

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118/ Docket No. UE-140617, Pacific Power & Light Company's Petition for Accounting Order at ¶ 1 (Apr. 14, 2014) ("Merwin Petition").

119/ Id. at ¶ 5.

120/ Docket Nos. UE-140762 and UE-140617, Order 03/01 at ¶ 10 (May 29, 2014).

the Merwin Petition in order to obtain "a more complete and fully developed record before we issue a decision on the eligibility of these amounts for inclusion in rates."[121/] Hence, the question as to whether the Company may collect any of the deferred Merwin Project costs in rates has been expressly reserved for determination in the GRC, including the propriety of accrued interest and special depreciation treatment.

Q. HOW DO YOU PROPOSE TO ACCOUNT FOR THE MERWIN DEFERRAL?

A. If the Commission determines that Merwin Fish Collector costs were prudently incurred, the Company should not be allowed any accrual of return, interest, or special depreciation treatment associated with deferred accounting. The deferral should provide the Company the opportunity to recover the undepreciated net plant associated with the Merwin Fish Collector in rate base, as is accomplished through the Company's pro-forma capital additions.

Q. SHOULD THE COMPANY BE GRANTED RECOVERY FOR DEFERRED RETURN ON RATE BASE?

A. No. Providing the Company the opportunity to recover the amounts accrued in relation to return on rate base works contrary to the Commission's ratemaking approach in Washington. Utilities should only be allowed to earn a return on utility property that is included in rate base through a general rate case. Providing the Company the opportunity to recover return on rate base through this deferral would result in double-counting the return component in revenue requirement. The Company would receive a return on rate base for the plant included as a post-test-year capital addition, and the Company would also receive return on rate base for the same plant in the deferral.

[121/] Id.

Q. SHOULD THE COMPANY BE GRANTED RECOVERY FOR DEFERRED DEPRECIATION EXPENSES?

A. No. Similar to return on rate base, depreciation will be double-counted in the Company's revenue requirement if it is included in both the deferral and in base rates. When the Company included the Merwin Fish Collector as a pro-forma plant addition in revenue requirement it accounted for a degree of depreciation. This depreciation would be recovered twice if it is also included in the deferral.

Q. DO YOU HAVE ANY ADDITIONAL CONCERNS WITH THE DEVELOPING TREND OF FREQUENT DEFERRED ACCOUNTING PETITIONS?

A. Yes. There are very serious issues of equity and fairness that must be addressed in regard to the current trend of deferred accounting petitions, which appear to be increasing in frequency. For instance, if the Company is permitted to increasingly shift more and more of its risk between rate cases to ratepayers through deferred accounting, then fairness would dictate that the return on equity which those same ratepayers must bear should be correspondingly reduced. In addition, the one-off nature of these requests brings up another fundamental matter of inequity surrounding the increased frequency of deferred accounting petitions:

> PacifiCorp, not its customers, controls the timing and the contents of its rate filings, and any supposed "need" for extraordinary relief since the last rate case rests solely on the Company's management …. Customers do not control the timing of rate cases, nor do they have the information or the resources to file petitions requesting deferred accounting of *benefits* the Company receives between rate cases. Rather, customers rely on the regulatory compact and the oversight of the Commission's rate case process to capture and balance both the costs and the benefits the Company realizes between rate cases. It would be unfair to allow [] PacifiCorp to shift responsibility for all of its expenses to customers through deferred accounting, while allowing the Company to enjoy the

benefits it receives until such a time as it chooses to file a rate case.[122]

In this light, I am concerned about the use of deferred accounting between rate cases. I would support the Commission in maintaining its high standards for deferred accounting treatment, ensuring that the fine balance is maintained between shareholder and ratepayer interests in between rate cases. The Commission can best maintain this balance by rejecting inappropriate and unjustified deferred accounting requests.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

[122] Docket No. UE-140617, ICNU Comments on Petition of PacifiCorp at 4 (May 27, 2014).